TECHNICAL REQUIREMENTS MANUAL (TRM)

FOR

COMANCHE PEAK STEAM ELECTRIC STATION

UNITS 1 AND 2

(continued)

11.0 USE AND APPLICATION

- NOTE -

For the purpose of the Technical Requirements, the Technical Requirements Manual terms specified below should be considered synonymous with the listed Technical Specification terms:

Technical Requirement	Technical Specifications
Technical Requirement (TR)	Technical Specifications (TS) or Specification(s)
Technical Requirement Surveillance (TRS)	Surveillance Requirement (SR)

11.1 Definitions

The definitions contained in the Technical Specifications Section 1.1, "Definitions" apply to the Technical Requirements contained in this manual.

11.2 Logical Connectors

The guidance provided for the use and application of logical connectors in Section 1.2, "Logical Connectors" of the Technical Specifications is applicable to the Technical Requirements contained in this manual.

11.3 Completion Times

The guidance provided for the use and application of Completion Times in Section 1.3, "Completion Times" of the Technical Specifications is applicable to the Technical Requirements contained in this manual.

11.4 Frequency

The guidance provided for the use and application of Frequency Requirements in Section 1.4, "Frequency" of the Technical Specifications is applicable to the Technical Requirements contained in this manual.

13.0 TECHNICAL REQUIREMENT(TR) LIMITING CONDITION FOR OPERATION (TR LCO) AND TECHNICAL REQUIREMENT SURVEILLANCE (TRS) APPLICABILITY

The guidance provided for the use and application of LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY in Section 3.0, “LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY” of the Technical Specifications is applicable to the Technical Requirements contained in this manual, except as noted below.

The guidance provided for the use and application of SURVEILLANCE REQUIREMENT (SR) APPLICABILITY in Section 3.0, “SURVEILLANCE REQUIREMENT (SR) APPLICABILITY” of the Technical Specifications is applicable to the Technical Requirements Surveillance (TRS) contained in this manual.

A cross reference between Section 13.0 of the Technical Requirements Manual and Section 3.0 of the Technical Specifications is as follows:

Technical Requirement Section	Technical Specification Section
TR LCO 13.0.1	LCO 3.0.1
TR LCO 13.0.2	LCO 3.0.2
N/A (See Note 1 below)	LCO 3.0.3
TR LCO 13.0.4	LCO 3.0.4
TR LCO 13.0.5	LCO 3.0.5
N/A (See Note 2 below)	LCO 3.0.6
TR LCO 13.0.7	LCO 3.0.7
TRS 13.0.1	SR 3.0.1
TRS 13.0.2	SR 3.0.2
TRS 13.0.3	SR 3.0.3
TRS 13.0.4	SR 3.0.4

(continued)

13.0 TR APPLICABILITY (continued)

- NOTES -

1. As part of the conversion to the Improved Technical Specifications in July 1999, certain Technical Specifications were relocated to the Improved Technical Requirements Manual. The shutdown requirements (similar to TS LCO 3.0.3) for each Technical Requirement are in three categories: (1) remains with the parent Technical Specification by direct reference to the Technical Specifications, (2) relocated by incorporation into the individual Technical Requirements (i.e. additional conditions were added), or (3) not applicable (i.e. all possible conditions were addressed within the TR LCO). Therefore, the TRM has no corresponding LCO 3.0.3 similar to the TS LCO 3.0.3.

   When a Required Action and Completion Time is not met and no associated Required Action is provided, the condition will be documented in the corrective action program.

2. Technical Specification LCO 3.0.6 provides entry into the Safety Function Determination Program (SFDP). The SFDP is not directly applied to the Technical Requirements Manual. However, TRM requirements may result in inoperable items which either support a parent Technical Specification (e.g. TR 13.3.1, “Reactor Trip System (RTS) Instrumentation Response Times”) or provide directions to declare the associated item inoperable and enter the applicable Technical Specification (e.g. TR 13.7.31, “Steam Generator Atmospheric Relief Valve (ARV) - Air Accumulator Tank”).

13.1 REACTIVITY CONTROL SYSTEMS

TR 13.1.31 Boration Injection System - Operating

TR LCO 13.1.31 Two boration injection subsystems shall be OPERABLE:

- NOTES -

1. TR LCO 13.0.4.c is applicable for entry into MODES 3 and 4 for the charging pump declared inoperable pursuant to TS 3.4.12 provided the charging pump is restored to OPERABLE status within 4 hours after entering MODE 3 or prior to the temperature of one or more of the RCS cold legs exceeding 375°F, whichever comes first.

2. In MODE 4 the positive displacement pump may be used in lieu of one of the required centrifugal charging pumps.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One boration injection subsystem inoperable (except due to required charging pump inoperable).	A.1 Restore boration injection subsystem to OPERABLE status.	72 hours
B. One charging pump inoperable.	B.1 Restore charging pump to OPERABLE status.	7 days
C. Two boration injection subsystems inoperable. <u>OR</u> Required Actions and associated Completion Times not met.	C.1 Initiate action to restore at least one boration injection subsystem to OPERABLE status. <u>AND</u> C.2 Initiate Engineering Evaluation to identify compensatory actions to be completed in a timely manner.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.1.31.1	Verify that the temperature of the flow path from the required boric acid storage tanks (including the tank solution temperature) is greater than or equal to 65°F.	7 days
TRS 13.1.31.2	Verify the boron concentration of the required boric acid storage tank has a minimum boron concentration of 7000 ppm.	7 days
TRS 13.1.31.3	Verify a minimum indicated borated water level of 50% of the required boric acid storage tank.	7 days
TRS 13.1.31.4	Verify that each valve (manual, power-operated, or automatic) in the required flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.	31 days
TRS 13.1.31.5	Verify that the flow path from the boric acid tanks delivers at least 30 gpm to the RCS.	18 months
TRS 13.1.31.6	Demonstrate the required centrifugal charging pump(s) OPERABLE by testing in accordance with the Inservice Testing Plan.	In accordance with the Inservice Testing Plan
TRS 13.1.31.7	Demonstrate the required positive displacement charging pump OPERABLE by performing TRS 13.1.31.5.	In accordance with TRS 13.1.31.5

13.1 REACTIVITY CONTROL SYSTEMS

TR 13.1.32 Boration Injection System - Shutdown

TR LCO 13.1.32 One boration injection subsystem shall be OPERABLE and capable of being powered from an OPERABLE emergency power source.

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required boration injection subsystem inoperable. OR Required boration injection subsystem not capable of being powered from an OPERABLE emergency power source.	A.1 Suspend all operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately

SURVEILLANCE REQUIREMENTS

- NOTES -

1. TRS 13.1.32.2, TRS 13.1.32.3, TRS 13.1.32.4, and TRS 13.1.32.5 are only required to be met when the boric acid storage tank is the required borated water source.

2. TRS 13.1.32.1, TRS 13.1.32.6, and TRS 13.1.32.7 are only required to be met when the RWST is the required borated water source.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TRS 13.1.32.1	-- - NOTE - Only required to be performed if the outside temperature is less than 40°F. -- Verify the RWST has a minimum solution temperature of 40°F.	24 hours
TRS 13.1.32.2	Verify that the temperature of the flow path and boric acid storage tank solution temperature is greater than or equal to 65°F.	7 days
TRS 13.1.32.3	Verify the boron concentration of the boric acid storage tank has a minimum boron concentration of 7000 ppm.	7 days
TRS 13.1.32.4	Verify a minimum indicated borated water level of 10% when using the boric acid pump from the boric acid storage tank.	7 days
TRS 13.1.32.5	Verify a minimum indicated borated water level of 20% when using gravity feed from the boric acid storage tank.	7 days
TRS 13.1.32.6	Verify the boron concentration of the RWST has a minimum boron concentration of 2400 ppm.	7 days
TRS 13.1.32.7	Verify a minimum indicated borated water level of 24% when using the RWST.	7 days
TRS 13.1.32.8	For the required flow path, verify 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.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TRS 13.1.32.9	Demonstrate the required positive displacement charging pump is OPERABLE by verifying that the flow path from the boric acid storage tanks via a boric acid transfer pump or gravity feed connection to the Reactor Coolant System is capable of delivering at least 30 gpm to the RCS.	18 months
TRS 13.1.32.10	Demonstrate the required centrifugal charging pump is OPERABLE by verifying, on recirculation flow, that a differential pressure across the pump of greater than or equal to 2370 psid is developed.	In accordance with the Inservice Testing Program

13.1 REACTIVITY CONTROL SYSTEMS

TR 13.1.37 Rod Group Alignment Limits and Rod Position Indicator

TR LCO 13.1.37 The Rod Position Deviation Monitor shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rods not within alignment limits.	A.1 Enter the applicable Condition(s) of TS 3.1.4	Immediately
B. One or more rod position indications inoperable.	B.1 Enter the applicable Condition(s) of TS 3.1.7	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.1.37.1	-- - NOTE - Only required to be performed when the rod position deviation monitor is discovered to be inoperable. -- Verify individual rod positions to be within alignment limit per Technical Specification SR 3.1.4.1.	4 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TRS 13.1.37.2	--- - NOTE - Only required to be performed when the rod position deviation monitor is discovered to be inoperable. --- Verify the OPERABILITY of the Demand Position Indication System and the Digital Rod Position Indication System (DPRI) while performing TRS 13.1.37.1 by verifying that the Demand Position Indication System and the DRPI, for each rod, agrees within 12 steps.	4 hours

13.1 REACTIVITY CONTROL SYSTEMS

TR 13.1.38 Control Bank Insertion Limits

TR LCO 13.1.38 The Control Bank Insertion Limit Monitor shall be OPERABLE.

APPLICABILITY: MODE 1,
MODE 2 with $k_{eff} \geq 1.0$

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Control bank insertion limits not met.	A.1 Enter the applicable Condition(s) of TS 3.1.6.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.1.38.1	-- - NOTE - Only required to be performed when the rod insertion limit monitor is discovered to be inoperable. -- Verify the position of each control bank to be within the insertion limit by verifying the individual rod positions per Technical Specification SR 3.1.6.2.	4 hours

13.1 REACTIVITY CONTROL SYSTEMS

TR 13.1.39 Rod Position Indication - Shutdown

TR LCO 13.1.39 One digital rod position indicator (DRPI), excluding demand position indication, shall be OPERABLE for each shutdown or control rod not fully inserted.

APPLICABILITY: MODES 3, 4 and 5

- NOTES -

1. This TR LCO is not applicable if the Rod Control System is incapable of rod withdrawal.

2. This TR LCO is not applicable if Keff is maintained less than or equal to 0.95, and no more than one shutdown or control bank is withdrawn from the fully inserted position.

3. The DRPI System may be de-energized to collect rod drop time data in accordance with SR 3.1.4.3 provided no more than one shutdown or control bank is withdrawn from the fully inserted position and the DRPI System is available during the withdrawal of the shutdown or control bank.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Less than the above required rod position indicator(s) OPERABLE.	A.1 Place the Rod Control System in a condition incapable of rod withdrawal.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and Completion Time of Condition A not met.	B.1 Action shall be initiated to place the unit in a lower MODE.	1 hour
	<u>AND</u>	
	B.2 Be in MODE 4	7 hours
	<u>AND</u>	
	B.3 Be in MODE 5	31 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.1.39.1	Verify each DRPI agrees within 12 steps of the group demand position when the rods are stationary and within 24 steps of the group demand position during rod motion over the full indicated range of rod travel.	Once prior to increasing Keff above 0.95 after each removal of the reactor vessel head.

13.2 POWER DISTRIBUTION LIMITS

TR 13.2.31 Moveable Incore Detection System

TR LCO 13.2.31 The Movable Incore Detection System shall be OPERABLE with:

a. At least 75% of the detector thimbles,

b. A minimum of two detector thimbles per core quadrant, and

c. Sufficient movable detectors, drive, and readout equipment to map these thimbles.

APPLICABILITY: When the Movable Incore Detection System is used for:

a. Recalibration of the Excore Neutron Flux Detection System, or

b. Monitoring the QUADRANT POWER TILT RATIO, or

c. Measurement of $F^{N}_{\Delta H}$, $F_Q(Z)$ and F_{xy}.

ACTIONS

- NOTE -

TR LCO 13.0.4.c is applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required movable incore detection system component(s) inoperable.	A.1 Restore the movable incore detection system to OPERABLE status.	Prior to using the system for the above listed monitoring and calibration functions.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.2.31.1	Verify Movable Incore Detection System OPERABILITY by irradiating each required detector and determining the acceptability of its voltage curve.	Within 24 hours prior to using the system for the above listed monitoring and calibration functions.

13.2 POWER DISTRIBUTION LIMITS

TR 13.2.32 Axial Flux Difference (AFD)

TR LCO 13.2.32 The Axial Flux Difference (AFD) Monitor Alarm shall be OPERABLE.

APPLICABILITY: MODE 1 with THERMAL POWER > 15% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. AFD not within limits of TS 3.2.3.	A.1 Enter applicable Condition(s) in TS 3.2.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.2.32.1	-- - NOTES - 1. Only required to be performed when the AFD Monitor Alarm is determined to be inoperable and for the first 24 hours after restoring to OPERABLE status. 2. Logged values shall be assumed to exist during interval preceding each logging. -- Monitor and log AFD to verify AFD is within limits for each OPERABLE excore channel.	1 hour for the first 24 hours that the AFD Monitor Alarm is inoperable <u>AND</u> 30 minutes when AFD Monitor Alarm is inoperable for > 24 hours <u>AND</u> ---------------------------- - NOTE - Only required if the AFD Monitor Alarm Cumulative penalty minute history data is not current. ---------------------------- 1 hour for the first 24 hours after restoring the AFD Monitor Alarm to OPERABLE status.

13.2 POWER DISTRIBUTION LIMITS

TR 13.2.33 Quadrant Power Tilt Ratio (QPTR) Alarm

TR LCO 13.2.33 The Quadrant Power Tilt Ratio (QPTR) Alarm shall be OPERABLE.

APPLICABILITY: MODE 1 with THERMAL POWER > 50% RATED THERMAL POWER.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. QPTR not within limit.	A.1 Enter the applicable Condition(s) of TS 3.2.4.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.2.33.1	-- - NOTE - Only required to be performed when the QPTR alarm is determined to be inoperable. -- Verify QPTR is within limit by calculation per Technical Specification SR 3.2.4.1.	12 hours

13.3 INSTRUMENTATION

TR 13.3.1 Reactor Trip System (RTS) Instrumentation Response Times

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- NOTE -

This Technical Requirement contains the listing of Reactor Trip System Instrumentation Response Time limits associated with Technical Specification SR 3.3.1.16 and the applicable Functions in Technical Specification Table 3.3.1-1.

Table 13.3.1-1 (Page 1 of 2)
Reactor Trip System (RTS) Instrumentation Response Time Limits

INITIATION SIGNAL	RESPONSE TIME IN SECONDS
1. Manual Reactor Trip	N.A.
2. Power Range Neutron Flux	
a. High Setpoint	$\leq$ 0.5 (1)
b. Low Setpoint	$\leq$ 0.5 (1)
3. Power Range Neutron Flux High Positive Rate	N.A.
4. Intermediate Range Neutron Flux	N.A.
5. Source Range Neutron Flux	N.A.
6. Overtemperature N-16	$\leq$ 8 (1,2)
7. Overpower N-16	$\leq$ 2 (1)
8. Pressurizer Pressure	
a. Pressurizer Pressure Low	$\leq$ 2
b. Pressurizer Pressure High	$\leq$ 2
9. Pressurizer Water Level High	N.A.
10. Reactor Coolant Flow Low	$\leq$ 1 (3)
11. Not Used	N.A.
12. Undervoltage - Reactor Coolant Pumps	$\leq$ 1.1 (4)
13. Underfrequency - Reactor Coolant Pumps	$\leq$ 0.6

(1) Neutron/gamma detectors are exempt from response time testing. Response time of the neutron/gamma flux signal portion of the channel shall be measured from detector output or input of first electronic component in a channel.

(2) Includes a maximum of 6 seconds for the RTD/thermal well response time.

(3) Includes Single Loop (Above P-8) and Two Loops (Above P-7 and Below P-8)

(4) An additional 0.4 seconds maximum calculated voltage decay time from the opening of RCP breaker until voltage reaches the undervoltage set-point provides an overall time $\leq$ 1.5 seconds

Table 13.3.1-1 (Page 2 of 2)
Reactor Trip System (RTS) Instrumentation Response Time Limits

INITIATION SIGNAL	RESPONSE TIME IN SECONDS
14. Steam Generator Water Level Low-Low	≤ 2
15. Not Used	N.A.
16. Turbine Trip	
a. Low Fluid Oil Pressure	N.A.
b. Turbine Stop Valve Closure	N.A.
17. Safety Injection Input from ESFAS	N.A.
18. Reactor Trip System Interlocks	
a. Intermediate Range Neutron Flux, P-6	N.A.
b. Low Power Reactor Trips Block, P-7	N.A.
c. Power Range Neutron Flux, P-8	N.A.
d. Power Range Neutron Flux, P-9	N.A.
e. Power Range Neutron Flux, P-10	N.A.
f. Turbine First Stage Pressure, P-13	N.A.
19. Reactor Trip Breakers	N.A.
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	N.A.
21. Automatic Trip Logic	N.A.

13.3 INSTRUMENTATION

TR 13.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation Response Times

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- NOTE -

This Technical Requirement contains the listing of ESFAS Instrumentation Response Time limits associated with Technical Specification SR 3.3.2.10 and the applicable functions in Technical Specification Table 3.3.2-1.

Table 13.3.2-1 (Page 1 of 6)
Engineered Safety Features Actuation System Instrumentation Response Time Limits

FUNCTIONAL UNIT AND INITIATION SIGNAL	RESPONSE TIME IN SECONDS
1. Safety Injection	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A
c. Containment Pressure High 1	
1. ECCS	≤ 27 (1,5,8) / 27 (4,6,8)
2. Reactor Trip	≤ 2 (15)
3. Containment Ventilation Isolation	N.A.
4. Station Service Water	N.A.
5. Component Cooling Water	N.A.
6. Essential Ventilation Systems	N.A.
7. Emergency Diesel Generator Operation	≤ 12
8. Control Room Emergency Recirculation	N.A.
9. Containment Spray	≤ 32 (7)

(1) Includes Diesel Generator starting delay.

(4) Diesel generator starting delay is <u>not</u> included. Includes centrifugal charging pumps only.

(5) Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is <u>not</u> included.

(6) Includes sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close).

(7) Includes Diesel Generator starting delay. Includes containment spray pumps only.

(8) RHR mini-flow valves are <u>not</u> included.

(15) The response time of less than or equal to 2 seconds is applicable for MODES 1 and 2 and is measured to the loss of stationary gripper coil only. The response time is not applicable (N.A.) for MODES 3 and 4.

Table 13.3.2-1 (Page 2 of 6)
Engineered Safety Features Actuation System Instrumentation Response Time Limits

FUNCTIONAL UNIT AND INITIATION SIGNAL	RESPONSE TIME IN SECONDS
1. Safety Injection (continued)	
d. Pressurizer Pressure Low	
1. ECCS	≤ 27 (1,5,8) / 27 (4,6,8)
2. Reactor Trip	≤ 2 (15)
3. Containment Ventilation Isolation	≤ 5 (16)
4. Station Service Water	N.A.
5. Component Cooling Water	N.A.
6. Essential Ventilation Systems	N.A.
7. Emergency Diesel Generator Operation	≤ 12
8. Control Room Emergency Recirculation	N.A.
9. Containment Spray	N.A.

(1) Includes Diesel Generator starting delay.

(4) Diesel generator starting delay is not included. Includes centrifugal charging pumps only.

(5) Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is not included.

(6) Includes sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close).

(8) RHR mini-flow valves are not included.

(15) The response time of less than or equal to 2 seconds is applicable for MODES 1 and 2 and is measured to the loss of stationary gripper coil only. The response time is not applicable (N.A.) for MODES 3 and 4.

(16) Includes containment pressure relief valves only.

Table 13.3.2-1 (Page 3 of 6)
Engineered Safety Features Actuation System Instrumentation Response Time Limits

FUNCTIONAL UNIT AND INITIATION SIGNAL	RESPONSE TIME IN SECONDS
1. Safety Injection (continued)	
e. Steam Line Pressure Low	
1. ECCS	≤ 37 (3,6,8) / 27 (4,6,8)
2. Reactor Trip	≤ 2 (15)
3. Containment Ventilation Isolation	N.A.
4. Station Service Water	N.A.
5. Component Cooling Water	N.A.
6. Essential Ventilation Systems	N.A.
7. Emergency Diesel Generator Operation	≤ 12
8. Control Room Emergency Recirculation	N.A.
9. Containment Spray	N.A.
2. Containment Spray	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.
c. Containment Pressure High 3	≤ 119(9)

(3) Includes Diesel Generator starting delay. Includes centrifugal charging pumps only.

(4) Diesel generator starting delay is not included. Includes centrifugal charging pumps only.

(6) Includes sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close).

(8) RHR mini-flow valves are not included.

(9) Includes containment spray header isolation valves only.

(15) The response time of less than or equal to 2 seconds is applicable for MODES 1 and 2 and is measured to the loss of stationary gripper coil only. The response time is not applicable (N.A.) for MODES 3 and 4.

Table 13.3.2-1 (Page 4 of 6)
Engineered Safety Features Actuation System Instrumentation Response Time Limits

FUNCTIONAL UNIT AND INITIATION SIGNAL	RESPONSE TIME IN SECONDS
3. Containment Isolation	
a. Phase A Isolation	
1. Manual Initiation	N.A.
2. Automatic Actuation Logic and Actuation Relays	N.A.
3. Safety Injection	≤ 17 (2,10) / 27 (1,10)
b. Phase B Isolation	
1. Manual Initiation	N.A.
2. Automatic Actuation Logic and Actuation Relays	N.A.
3. Containment Pressure High 3	N.A.
4. Steam Line Isolation	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.
c. Containment Pressure High 2	≤ 7
d. Steam Line Pressure	
1. Steam Line Pressure Low	≤ 7
2. Steam Line Pressure Negative Rate High	≤ 7

(1) Includes Diesel Generator starting delay.

(2) Diesel generator starting delay is not included.

(10) Includes Containment Pressure High 1, Pressurizer Pressure Low, and Steam Line Pressure Low initiation signals.

Table 13.3.2-1 (Page 5 of 6)
Engineered Safety Features Actuation System Instrumentation Response Time Limits

FUNCTIONAL UNIT AND INITIATION SIGNAL	RESPONSE TIME IN SECONDS
5. Turbine Trip and Feedwater Isolation	
a. Automatic Actuation Logic and Actuation Relays	N.A.
b. Steam Generator Water Level High-High, P-14	≤ 11 (11)
c. Safety Injection	≤ 7 (10,11)
6. Auxiliary Feedwater	
a. Automatic Actuation Logic and Actuation Relays	N.A.
b. Not Used	N.A.
c. Steam Generator Water Level Low-Low	≤ 60 (12) / 85 (13)
d. Safety Injection	≤ 60 (1,10,12)
e. Loss of Offsite Power	≤ 58 (1,14)
f. Not Used	N.A.
g. Trip of all Main Feedwater Pumps	N.A.
h. Not Used	N.A.

(1) Includes Diesel Generator starting delay.

(10) Includes Containment Pressure High 1, Pressurizer Pressure Low, and Steam Line Pressure Low initiation signals.

(11) Includes Feedwater Isolation only. Turbine Trip is not included.

(12) Includes motor driven auxiliary feedwater pumps and feedwater split flow bypass valves only.

(13) Includes turbine driven auxiliary feedwater pump and feedwater split flow bypass valves only.

(14) Includes motor driven auxiliary feedwater pumps only.

Table 13.3.2-1 (Page 6 of 6)
Engineered Safety Features Actuation System Instrumentation Response Time Limits

FUNCTIONAL UNIT AND INITIATION SIGNAL	RESPONSE TIME IN SECONDS
7. Automatic Switchover to Containment Sump	
a. Automatic Actuation Logic and Actuation Relays	N.A.
b. Refueling Water Storage Tank Level Low-Low Coincident with Safety Injection	≤ 30
8. ESFAS Interlocks	
a. Reactor Trip, P-4	N.A.
b. Pressurizer Pressure, P-11	N.A.

13.3 INSTRUMENTATION

TR 13.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation Response Times

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- NOTE -

This Technical Requirement contains the listing of Loss of Power Diesel Generator Start Instrumentation Response Time limits associated with Technical Specification SR 3.3.5.4 and applicable functions in Technical Specification Table 3.3.5-1.

Table 13.3.5-1
Loss of Power Diesel Generator Start Instrumentation Response Time Limits

INITIATION SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Automatic Actuation Logic and Actuation Relays	N.A.
2. Preferred Offsite Source bus UV	N.A.
3. Alternate Offsite Source bus UV	N.A.
4. 6.9 KV Class 1E Bus Undervoltage	≤ 2 (1)
5. 6.9 KV Degraded Voltage	≤ 10 (1, 2, 3) / ≤ 63 (1, 2, 4)
6. 480 V Class 1E Bus Low Grid Undervoltage	≤ 63 (1,2)
7. 480V Class 1E Bus Degraded Voltage	≤ 10 (1, 2, 3) / ≤ 63 (1, 2, 4)

(1) Response time measured to output of undervoltage channel only.

(2) Two additional seconds allowable for alternate offsite source breaker trip functions.

(3) With SI

(4) Without SI

13.3 INSTRUMENTATION

TR 13.3.31 Seismic Instrumentation

TR LCO 13.3.31 The seismic monitoring instrumentation shall be OPERABLE.

APPLICABILITY: At all times

ACTIONS

- NOTE -

TR LCO 13.0.4.c is applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Seismic monitoring instrument inoperable.	A.1 Restore seismic monitoring instrument to OPERABLE status.	30 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.3.31.1	Perform a CHANNEL CHECK.	31 days
TRS 13.3.31.2	Perform a CHANNEL CALIBRATION.	18 months
TRS 13.3.31.3	-- - NOTE - Setpoint verification is not required. -- Perform a CHANNEL OPERATIONAL TEST.	184 days

13.3 INSTRUMENTATION

TR 13.3.32 Source Range Neutron Flux

TR LCO 13.3.32 2 channels for source range neutron flux monitoring shall be OPERABLE.

APPLICABILITY: MODES 3, 4, and 5

- NOTE -

Only applicable if the Rod Control System is not capable of rod withdrawal and all control rods are fully inserted.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required Source Range Neutron Flux channel inoperable.	A.1 Restore channel to OPERABLE status. <u>OR</u> A.2 Suspend all operations involving positive reactivity changes.	48 hours 49 hours
B. Both required Source Range Neutron Flux channels inoperable.	B.1 Restore one channel to OPERABLE status. <u>OR</u> B.2 Suspend all operations involving positive reactivity changes.	4 hours 4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.3.32.1	Perform CHANNEL CHECK.	12 hours
TRS 13.3.32.2	- NOTE - Not required for the Gamma-Metrics range detectors. Perform COT.	184 days
TRS 13.3.32.3	- NOTES - 1. Neutron detectors may be excluded from CHANNEL CALIBRATION. 2. For the Westinghouse BF_3 detectors, with the high voltage setting varied as recommended by the manufacturer, an initial discriminator bias curve shall be measured for each detector. Subsequent discriminator bias curves shall be obtained, evaluated and compared to the initial curves. Perform CHANNEL CALIBRATION.	18 months

13.3 INSTRUMENTATION

TR 13.3.33 Turbine Overspeed Protection

TR LCO 13.3.33 At least one Turbine Overspeed Protection Sub-system shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

- NOTE -
Not applicable in MODES 2 and 3 with all main steam line isolation valves and associated bypass valves in the closed position.

ACTIONS

- NOTE -
Separate Condition entry allowed for each steam line.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One stop valve or one control valve per high pressure turbine steam line inoperable.	A.1 Restore the inoperable valve(s) to OPERABLE status.	72 hours
	<u>OR</u>	
	A.2 Close at least one valve in the affected steam line(s).	78 hours
	<u>OR</u>	
	A.3 Isolate the turbine from the steam supply.	78 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One stop valve or one control valve per low pressure turbine steam line inoperable.	B.1 Restore the inoperable valve(s) to OPERABLE status.	72 hours
	<u>OR</u>	
	B.2 Close at least one valve in the affected steam line(s).	78 hours
	<u>OR</u>	
	B.3 Isolate the turbine from the steam supply.	78 hours
C. Both Overspeed Protection Sub-systems inoperable.	C.1 Isolate the turbine from the steam supply.	6 hours
D. Required Actions and associated Completion Times not met.	D.1 Initiate action to place the unit in a lower MODE.	1 hour
	<u>AND</u>	
	D.2 Be in MODE 3.	7 hours
	<u>AND</u>	
	D.3 Be in MODE 4.	13 hours

SURVEILLANCE REQUIREMENTS

- NOTE -
The provisions of TRS 13.0.4 are not applicable.

SURVEILLANCE		FREQUENCY
TRS 13.3.33.1	Test the Turbine Trip Block using the Automatic Turbine Tester (ATT).	14 days
TRS 13.3.33.2	Cycle each of the following valves through at least one complete cycle from the running position using the manual test or Automatic Turbine Tester (ATT). a. Four high pressure turbine stop valves, b. Four high pressure turbine control valves, c. Four low pressure turbine stop valves, and d. Four low pressure turbine control valves.	12 weeks
TRS 13.3.33.3	Deleted	
TRS 13.3.33.4	Disassemble at least one high pressure turbine stop valve and one high pressure control valve and perform a visual and surface inspection of valve seats, disks and stems and verify no unacceptable flaws are found. If unacceptable flaws are found, all other valves of that type shall be inspected.	40 months
TRS 13.3.33.5	Visually inspect the disks and accessible portions of the shafts of at least one low pressure turbine stop valve and one low pressure control valve and verify no unacceptable flaws are found. If unacceptable flaws are found, all other valves of that type shall be inspected.	40 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TRS 13.3.33.6	Test the Hardware Overspeed Sub-system 2 of 3 relay logic and output relays.	18 months

13.3 INSTRUMENTATION

TR 13.3.34 Plant Calorimetric Measurement

TR LCO 13.3.34 The Leading Edge Flow Meter (LEFM) shall be used for the completion of SR 3.3.1.2.

APPLICABILITY: MODE 1 > 15% RTP*

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LEFM not available	A.1 Restore LEFM to available status	Prior to performance of SR 3.3.1.2
B. Required Action or Completion Time of Condition A not met	B.1 Ensure THERMAL POWER ≤ 98.6% RTP (3411 MW_{th}).	Prior to performance of SR 3.3.1.2
	<u>AND</u>	
	B.2 Perform SR 3.3.1.2 using feedwater venturis	As required by SR 3.3.1.2
	<u>AND</u>	
	B.3 Maintain THERMAL POWER ≤ 98.6% RTP (3411 MW_{th})	Until LEFM is restored to available status and SR 3.3.1.2 is performed using LEFM.

* This TRM requirement applies to Unit 2 only until implementation of the 1.4% uprate for Unit 1 during 1RF09.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.3.34.1	Verify availability of LEFM using self-diagnostics	Prior to performance of SR 3.3.1.2

13.4 REACTOR COOLANT SYSTEM (RCS)

TR 13.4.14 RCS Pressure Isolation Valves

This Technical Requirement contains a listing of the RCS Pressure Isolation Valves (PIVs) subject to Technical Specification 3.4.14.

Table 13.4.14-1
Reactor Coolant System Pressure Isolation Valves

VALVE NUMBER	FUNCTION
8948 A, B, C, D	Accumulator Tank Discharge
8956 A, B, C, D	Accumulator Tank Discharge
8905 A, B, C, D	SI Hot Leg Injection
8949 A, B, C, D	SI Hot Leg Injection
8818 A, B, C, D	RHR Cold Leg Injection
8819 A, B, C, D	SI Cold Leg Injection
8701 A, B	RHR Suction Isolation
8702 A, B	RHR Suction Isolation
8841 A, B	RHR Hot Leg Injection
8815	CCP Cold Leg Injection
8900 A, B, C, D	CCP Cold Leg Injection

13.4 REACTOR COOLANT SYSTEM

TR 13.4.31 Loose Part Detection System

TR LCO 13.4.31 The Loose-Part Detection System shall be OPERABLE.

APPLICABILITY: MODES 1 and 2

ACTIONS

- NOTE -

TR LCO 13.0.4.c is applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. With one or more required Loose-Part Detection System channels inoperable.	A.1 Restore required channels to Operable status.	30 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.4.31.1	Perform a CHANNEL CHECK.	24 hours
TRS 13.4.31.2	- NOTE - Setpoint verification is not required. Perform a CHANNEL OPERATIONAL TEST.	31 days
TRS 13.4.31.3	Perform a CHANNEL CALIBRATION.	18 months

13.4 REACTOR COOLANT SYSTEM

TR 13.4.33 Reactor Coolant System (RCS) Chemistry

TR LCO 13.4.33 The Reactor Coolant System chemistry shall be maintained within the limits specified in Table 13.4.33-1.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
-- - NOTE - Only applicable in MODES 1, 2, 3 and 4. -- A. One or more chemistry parameters in excess of its Steady-State Limit but within its Transient Limit.	A.1 Restore parameter to within Steady-State limit.	24 hours
-- - NOTE - Only applicable in MODES 1, 2, 3 and 4. -- B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more chemistry parameters in excess of its Transient Limit.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
-- - NOTE - Applicable in all conditions other than MODES 1, 2, 3 and 4. -- C. Concentration of chloride or floride in the RCS in excess of its Steady-State Limit.	C.1 Restore concentration of chloride and floride to within its Steady-State limit.	24 hours
-- - NOTES - 1. All Required Actions must be completed whenever this Condition is entered. 2. Applicable in all conditions other than MODES 1, 2, 3 and 4. -- D. Required Action and associated Completion Time of Condition C not met. <u>OR</u> Concentration of chloride or fluoride in the RCS in excess of its Transient Limit.	D.1 Initiate action to reduce the pressurizer pressure to $\leq$ 500 psig. <u>AND</u> D.2 Perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the RCS; determine that the RCS remains acceptable for continued operation.	Immediately Prior to increasing the pressurizer pressure > 500 psig. <u>AND</u> Prior to proceeding to MODE 4.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.4.33.1	-- - NOTES - 1. Not required to be performed for dissolved oxygen when $T_{avg} \leq 250°F$. 2. Not required to be met for Chloride and Fluoride until 72 hours after entry into MODE 6 from a defueled state. -- Verify the RCS chemistry within the limits by analysis of parameter specified in Table 13.4.33-1.	72 hours

Table 13.4.33-1
Reactor Coolant System Chemistry Limits

PARAMETER	STEADY-STATE LIMIT	TRANSIENT LIMIT
Dissolved Oxygen [a]	≤ 0.10 ppm	≤ 1.00 ppm
Chloride [b]	≤ 0.15 ppm	≤ 1.50 ppm
Fluoride [b]	≤ 0.15 ppm	≤ 1.50 ppm

(a) Limit not applicable with T_{avg} less than or equal to 250 °F.

(b) Limit not applicable when Reactor Coolant System is defueled.

13.4 REACTOR COOLANT SYSTEM

TR 13.4.34 Pressurizer

TR LCO 13.4.34 The pressurizer temperature shall be limited to:

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

b. A maximum cooldown of 200°F in any 1 hour period.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------------------------------ - NOTE - All Required Actions must be completed whenever this Condition is entered. ------------------------------------ Pressurizer temperature in excess of the required limits.	A.1 Restore pressurizer temperature to within limits. AND A.2 Perform an engineering evaluation to determine that the effects of the out-of-limit condition on the structural integrity of the pressurizer remains acceptable for continued operation.	30 minutes As assigned by the Shift Manager, commensurate with safety.
B. Required Actions and associated Completion Times of Condition A not met.	B.1 Be in at least MODE 3. AND B.2 Reduce pressurizer pressure to < 500 psig.	6 hours 36 hours
C. Required Actions and associated Completion Times of Condition B not met.	C.1 Be in MODE 4. AND C.2 Be in MODE 5.	6 hours 30 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.4.34.1	-- - NOTE - Only required to be performed during system heatup and cooldown. --	
	Verify the pressurizer temperatures to be within the limits.	30 minutes

13.4 REACTOR COOLANT SYSTEM

TR 13.4.35 Reactor Coolant System (RCS) Vent Specification

TR LCO 13.4.35 At least one Reactor Coolant System vent path consisting of two vent valves in series powered from emergency busses shall be OPERABLE and closed at each of the following locations:

a. Reactor vessel head, and

b. Pressurizer steam space.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Reactor Coolant System vent path inoperable.	A.1 Close the inoperable vent path and remove power from the valve actuators of all the vent valves in the inoperable vent path.	Immediately
	AND	
	A.2 Restore the inoperable vent path to OPERABLE status.	30 days
B. Both Reactor Coolant System vent paths inoperable.	B.1 Close the inoperable vent paths and remove power from the valve actuators of all the vent valves in the inoperable vent paths.	Immediately
	AND	
	B.2 Restore at least one of the vent paths to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Actions and associated Completion Times of Condition A or B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.4.35.1	Verify all manual isolation valves in each vent path are locked in the open position.	18 months
TRS 13.4.35.2	Cycle each vent valve path through at least one complete cycle of full travel from the control room.	18 months
TRS 13.4.35.3	Verify flow through the Reactor Coolant System vent paths during venting.	18 months

13.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

TR 13.5.31 ECCS - Containment Debris

TR LCO 13.5.31 Pursuant to TS 3.5.2 and 3.5.3, the containment shall be free of loose debris which could restrict, during a LOCA, the pump suctions for the ECCS train(s) required to be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Loose debris left in containment which could restrict, during a LOCA, the pump suctions for the ECCS train(s) required to be OPERABLE.	A.1 Enter the applicable Condition(s) of TS 3.5.2 or 3.5.3 for affected ECCS train(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.5.31.1	-- - NOTE - This surveillance not required for entry into MODE 4 provided that for the entire time below MODE 4, (1) restrictions and access controls used for MODES 1 through 4 are maintained and (2) TRS 13.5.31.2 is performed as required to support containment entries. -- Perform a visual inspection of accessible areas of containment to verify that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restriction of the pump suctions during LOCA conditions.	Once prior to entering MODE 4

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
TRS 13.5.31.2	-- - NOTE - Only required to be performed during periods when containment entries are made. -- Perform a visual inspection of all areas within containment affected by a containment entry to verify that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restriction of the pump suctions during LOCA conditions.	24 hours

13.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

TR 13.5.32 ECCS - Pump Line Flow Rates

TR LCO 13.5.32 Pursuant to TS 3.5.2 and 3.5.3, the pump lines for the ECCS train(s) required to be OPERABLE shall have the required flow rates.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pump lines for the ECCS train(s) required to be OPERABLE do not meet required flow rates.	A.1 Enter the applicable Condition(s) of TS 3.5.2 and 3.5.3 for affected ECCS train(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.5.32.1	Performing a flow balance test, during shutdown, and verify that: a. For centrifugal charging pump lines, with a single pump running: 1. The sum of the injection line flow rates, excluding the highest flow rate, is ≥ 245 gpm, and 2. The total pump flow rate is ≤ 560 gpm. b. For safety injection pump lines, with a single pump running: 1. The sum of the cold leg injection line flow rates, excluding the highest flow rate, is ≥ 400 gpm, and 2. The total pump flow rate is ≤ 675 gpm. c. For RHR pump lines, with a single pump running, the sum of the cold leg injection line flow rates is ≥ 4652 gpm.	Once following completion of modifications to the ECCS subsystems that alter the subsystem flow characteristics.

13.6 CONTAINMENT SYSTEMS

TR 13.6.3 Containment Isolation Valves

This Technical Requirement contains the listing of Containment Isolation Valves subject to CPSES Technical Specification 3.6.3. Commensurate with Technical Specification Surveillance Requirement SR 3.6.3.5, Table 13.6.3-1 also contains the isolation time limit for each automatic power operated containment isolation valve.

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
1. Phase "A" Isolation Valves				
HV-2154	20	Feedwater Sample (FW to Stm Gen #1)	5	N.A., Note 9
HV-2155	22	Feedwater Sample (FW to Stm Gen #2)	5	N.A., Note 9
HV-2399	27	Blowdown From Steam Generator #3	5	N.A.
HV-2398	28	Blowdown From Steam Generator #2	5	N.A.
HV-2397	29	Blowdown From Steam Generator #1	5	N.A.
HV-2400	30	Blowdown From Steam Generator #4	5	N.A
8152	32	Letdow Line to Letdown Heat Exchanger	10	C
8160	32	Letdow Line to Letdown Heat Exchanger	10	C
8890A	35	RHR to Cold Leg Loops #1 & #2 Test Line	15	N.A.
8890B	36	RHR to Cold Leg Loops #3 & #4 Test Line	15	N.A.
8047	41	Reactor Makeup Water to Pressure Relief Tank & RC Pump Stand Pipe	10	C
8843	42	SI to RC System Cold Leg Loops #1, #2, #3, & #4 Test Line	10	N.A.
8881	43	SI to RC System Hot Leg Loops #2 & #3 Test Line	10	N.A.
8824	44	SI to RC System Hot Leg Loops #1 & #4 Test Line	10	N.A.
8823	45	SI to RC System Cold Leg Loops #1, #2, #3, & #4 Test Line	10	N.A.
8100	51	Seal Water Return and Excess Letdown	10	C
8112	51	Seal Water Return and Excess Letdown	10	C
7136	52	RCDT Heat Exchanger to Waste Hold up Tank	10	C
LCV-1003	52	RCDT Heat Exchanger to Waste Hold up Tank	10	C
HV-5365	60	Demineralized Water Supply	10	C
HV-5366	60	Demineralized Water Supply	10	C
HV-5157	61	Containment Sump Pump Discharge	5	C
HV-5158	61	Containment Sump Pump	5	C

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
HV-3487	62	Instrument Air to Containment	5	C
8825	63	RHR to Hot Leg Loops #2 & #3 Test Line	15	N.A.
HV-2405	73	Sample from Steam Generator #1	5	N.A.
HV-4170	74	RC Sample from Hot Legs	5	C
HV-4168	74	RC Sample from Hot Leg #1	5	C
HV-4169	74	RC Sample from Hot Leg #4	5	C
HV-2406	76	Sample from Steam Generator #2	5	N.A.
HV-4167	77	Pressurizer Liquid Space Sample	5	C
HV-4166	77	Pressurizer Liquid Space Sample	5	C
HV-4176	78	Pressurizer Steam Space Sample	5	C
HV-4165	78	Pressurizer Steam Space Sample	5	C
HV-2407	79	Sample from Steam Generator #3	5	N.A.
HV-4175	80	Accumulators	5	C
HV-4171	80	Sample From Accumulator #1	5	C
HV-4172	80	Sample From Accumulator #2	5	C
HV-4173	80	Sample From Accumulator #3	5	C
HV-4174	80	Sample From Accumulator #4	5	C
HV-7311	81	RC PASS Sample Discharge to RCDT	5	C
HV-7312	81	RC PASS Sample Discharge to RCDT	5	C
HV-2408	82	Sample from Steam Generator #4	5	N.A.
8871	83	Accumulator Test and Fill	10	C
8888	83	Accumulator Test and Fill	10	C
8964	83	Accumulator Test and Fill	10	C
HV-5556	84	Containment Air PASS Return	5	C
HV-5557	84	Containment Air PASS Return	5	C
HV-5544	94	Radiation Monitoring Sample	5	C
HV-5545	94	Radiation Monitoring Sample	5	C

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
HV-5558	97	Containment Air PASS Inlet	5	C
HV-5559	97	Containment Air PASS Inlet	5	C
HV-5560	100	Containment Air PASS Inlet	5	C
HV-5561	100	Containment Air PASS Inlet	5	C
HV-5546	102	Radiation Monitoring Sample Return	5	C
HV-5547	102	Radiation Monitoring Sample Return	5	C
8880	104	N_2 Supply to Accumulators	10	C
7126	105	H_2 Supply to RC Drain Tank	10	C
7150	105	H_2 Supply to RC Drain Tank	10	C
HV-4710	111	CCW Supply to Excess Letdown & RC Drain Tank Heat Exchanger	5	N.A.
HV-4711	112	CCW Return to Excess Letdown & RC Drain Tank Heat Exchanger	5	N.A.
HV-3486	113	Service Air to Containment	5	C
HV-4725	114	Containment CCW Drain Tank Pumps Discharge	10	C
HV-4726	114	Containment CCW Drain Tank Pumps Discharge	10	C
8027	116	Nitrogen Supply to PRT	10	C
8026	116	Nitrogen Supply to PRT	10	C
HV-6084	120	Chilled Water Supply to Containment Coolers	15	C
HV-6082	121	Chilled Water Return to Containment Coolers	15	C
HV-6083	121	Chilled Water Return to Containment Coolers	15	C
HV-4075B	124	Fire Protection System Isolation	10	C
HV-4075C	124	Fire Protection System Isolation	10	C
2. Phase “B” Isolation Valves				
HV-4708	117	CCW Return From RCP”s Motors	30	C
HV-4701	117	CCW Return From RCP”s Motors	30	C
HV-4700	118	CCW Supply To RCP”s Motors	30	C

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
HV-4709	119	CCW Return From RCP"s Thermal Barrier	15	C
HV-4696	119	CCW Return From RCP"s Thermal Barrier	15	C
3. Containment Ventilation Isolation Valves				
HV-5542	58	Hydrogen Purge Supply	N.A.	C
HV-5543	58	Hydrogen Purge Supply	N.A.	C
HV-5563	58	Hydrogen Purge Supply	N.A.	C
HV-5540	59	Hydrogen Purge Exhaust	N.A.	C
HV-5541	59	Hydrogen Purge Exhaust	N.A.	C
HV-5562	59	Hydrogen Purge Exhaust	N.A.	C
HV-5536	109	Containment Purge Air Supply	N.A.	C
HV-5537	109	Containment Purge Air Supply	N.A.	C
HV-5538	110	Containment Purge Air Exhaust	N.A.	C
HV-5539	110	Containment Purge Air Exhaust	N.A.	C
HV-5548	122	Containment Pressure Relief	5	C Note 8
HV-5549	122	Containment Pressure Relief	5	C Note 8
4. Manual Valves				
MS-711#	4a	TDAFW Pump Bypass Warm-up Valve	N.A.	N.A.
MS-390	5a	N_2 Supply to Steam Generator #1	N.A.	N.A.
MS-387	9a	N_2 Supply to Steam Generator #2	N.A.	N.A.
MS-384	13a	N_2 Supply to Steam Generator #3	N.A.	N.A.
MS-712#	17a	TDAFW Pump Bypass Warm-up Valve	N.A.	N.A.
MS-393	18a	N_2 Supply to Steam Generator #4	N.A.	N.A.
FW-116	20	Feedwater Sample (FW to Stm Gen #1)	N.A.	N.A., Note 9
FW-113	22	Feedwater Sample (FW to Stm Gen #2)	N.A.	N.A., Note 9
FW-106	20b	N_2 Supply to Steam Generator #1	N.A.	N.A.

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
FW-104	22b	N_2 Supply to Steam Generator #2	N.A.	N.A.
FW-102	24b	N_2 Supply to Steam Generator #3	N.A.	N.A.
FW-108	26b	N_2 Supply to Steam Generator #4	N.A.	N.A.
7135#	52	RCDT Heat Exchanger to Waste Holdup Tank	N.A.	C
MS-101	4	TDAFWP Steam Supply	N.A.	N.A.
MS-128	17	TDAFWP Steam Supply	N.A.	N.A.
SF-011	56	Refueling Water Purification to Refueling Cavity	N.A.	C
SF-012	56	Refueling Water Purification to Refueling Cavity	N.A.	C
SF-021	67	Refueling Cavity to Refueling Water Purification	N.A.	C
SF-022	67	Refueling Cavity to Refueling Water Purification	N.A.	C
1SF-053 2SF-0055	71	Refueling Cavity Skimmer Pump Discharge	N.A.	C
1SF-054 2SF-0056	71	Refueling Cavity Skimmer Pump Discharge	N.A.	C
SI-8961#	83	Accumulator Test and Fill	N.A.	N.A.
HV-2333B#	2	MSIV Bypass from Steam Generator #1	N.A.	Note 1
HV-2334B#	7	MSIV Bypass from Steam Generator #2	N.A.	Note 1
HV-2335B#	11	MSIV Bypass from Steam Generator #3	N.A.	Note 1
HV-2336B#	15	MSIV Bypass from Steam Generator #4	N.A.	Note 1
1BS-0016#	130	Airlock Hydraulic System	N.A.	N.A.
1BS-0017#	130	Airlock Hydraulic System	N.A.	N.A.
1BS-0030#	131	Airlock Hydraulically Operated Equalization	N.A.	Notes 5, 6, 7
1BS-0025#	131	Airlock Hydraulically Operated Equalization	N.A.	Notes 5, 6, 7
1BS-0056#	131a	Airlock Manual Equalization	N.A.	Notes 5, 6
1BS-0044#	131a	Airlock Manual Equalization	N.A.	Notes 5, 6
1BS-0029#	131a	Airlock Manual Equalization	N.A.	Notes 5, 6
1BS-0015#	131a	Airlock Manual Equalization	N.A.	Notes 5, 6

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
BS-0202#	132	Airlock Manual Equalization	N.A.	Notes 5, 6, 7
BS-0203#	132	Airlock Manual Equalization	N.A.	Notes 5, 6, 7
2BS-0016#	133	Airlock Hydraulic System	N.A.	Notes 5, 6
2BS-0017#	133	Airlock Hydraulic System	N.A.	Notes 5, 6
2BS-0039#	133	Airlock Hydraulic System	N.A.	Notes 5, 6
2BS-0040#	133	Airlock Hydraulic System	N.A.	Notes 5, 6
2BS-0030#	134	Airlock Hydraulically Operated Equalization	N.A.	Notes 5, 6, 7
2BS-0025#	134	Airlock Hydraulically Operated Equalization	N.A.	Notes 5, 6, 7
2BS-0056#	134a	Airlock Manual Equalization	N.A.	Notes 5, 6
2BS-0044#	134a	Airlock Manual Equalization	N.A.	Notes 5, 6
2BS-0029#	134a	Airlock Manual Equalization	N.A.	Notes 5, 6
2BS-0015#	134a	Airlock Manual Equalization	N.A.	Notes 5, 6
5. Power-Operated Isolation Valves				
HV-2452-1	4	Main Steam to Aux. FPT From Steam Line # 4	N.A.	N.A
PV-2325	5	Atmospheric Relief Steam Generator	N.A.	Note 3
PV-2326	9	Atmospheric Relief Steam Generator	N.A.	Note 3
PV-2327	13	Atmospheric Relief Steam Generator	N.A.	Note 3
HV-2452-2	17	Main Steam to Aux. FPT From Steam Line # 1	N.A.	N.A.
PV-2328	18	Atmospheric Relief Steam Generator	N.A.	Note 3
HV-2491A	20a	Auxiliary Feedwater to Steam Generator #1	N.A.	N.A.
HV-2491B	20a	Auxiliary Feedwater to Steam Generator #1	N.A.	N.A.
HV-2492A	22a	Auxiliary Feedwater to Steam Generator #2	N.A.	N.A.
HV-2492B	22a	Auxiliary Feedwater to Steam Generator #2	N.A.	N.A.
HV-2493A	24a	Auxiliary Feedwater to Steam Generator #3	N.A.	N.A.
HV-2493B	24a	Auxiliary Feedwater to Steam Generator #3	N.A.	N.A.
HV-2494A	26a	Auxiliary Feedwater to Steam Generator #4	N.A.	N.A.
HV-2494B	26a	Auxiliary Feedwater to Steam Generator #4	N.A.	N.A.

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
8701B	33	RHR From Hot Leg Loop #4	N.A.	N.A.
8701A	34	RHR From Hot Leg Loop #1	N.A.	N.A.
8809A	35	RHR From Cold Leg Loops #1 and #2	N.A.	N.A.
8809B	36	RHR From Cold Leg Loops #3 and #4	N.A.	N.A.
8801A	42	Safety Injection to Cold Leg Loops #1, #2, #3, and #4	N.A.	N.A.
8801B	42	Safety Injection to Cold Leg Loops #1, #2, #3, and #4	N.A.	N.A.
8802A	43	SI Injection to RCS Hot Leg Loops #2 and #3	N.A.	N.A.
8802B	44	SI Injection to RCS Hot Leg Loops #1 and #4	N.A.	N.A.
8835	45	SI Injection to RCS Cold Leg Loops #1, #2, #3, and #4	N.A.	N.A.
8351A	47	Seal Injection to RC Pump (Loop #1)	N.A.	N.A.
8351B	48	Seal Injection to RC Pump (Loop #2)	N.A.	N.A.
8351C	49	Seal Injection to RC Pump (Loop #3)	N.A.	N.A.
8351D	50	Seal Injection to RC Pump (Loop #4)	N.A.	N.A.
HV-4777	54	Containment Spray to Spray Header (Train B)	N.A.	N.A.
HV-4776	55	Containment Spray to Spray Header (Train A)	N.A.	N.A.
8840	63	RHR to Hot Leg Loops #2 and #3	N.A.	N.A.
8811A	125	Containment Recirc. Sump to RHR Pumps (Train A)	N.A.	N.A.
8811B	126	Containment Recirc. Sump to RHR Pumps (Train B)	N.A.	N.A.
HV-4782	127	Containment Recirc. to Spray Pumps (Train A)	N.A.	N.A.
HV-4783	128	Containment Recirc. to Spray Pumps (Train B)	N.A.	N.A.
6. Check Valves				
8818A	35	RHR to Cold Leg Loop #1	N.A.	N.A.
8818B	35	RHR to Cold Leg Loop #2	N.A.	N.A.
8818C	36	RHR to Cold Leg Loop #3	N.A.	N.A.
8818D	36	RHR to Cold Leg Loop #4	N.A.	N.A.
8046	41	Reactor Makeup Water to Pressurizer Relief Tank and RC Pump Stand Pipe	N.A.	C

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
8815	42	High Head Safety Injection to Cold Leg Loops #1, #2, #3, and #4	N.A.	N.A.
SI-8905B	43	SI to RC System Hot Leg Loop #2	N.A.	N.A.
SI-8905C	43	SI to RC System Hot Leg Loop #3	N.A.	N.A.
SI-8905A	44	SI to RC System Hot Leg Loop #1	N.A.	N.A.
SI-8905D	44	SI to RC System Hot Leg Loop #4	N.A.	N.A.
SI-8819A	45	SI to RC System Cold Leg Loop #1	N.A.	N.A.
SI-8819B	45	SI to RC System Cold Leg Loop #2	N.A.	N.A.
SI-8819C	45	SI to RC System Cold Leg Loop #3	N.A.	N.A.
SI-8819D	45	SI to RC System Cold Leg Loop #4	N.A.	N.A.
8381	46	Charging Line to Regenerative Heat Exchanger	N.A.	C
CS-8368A	47	Seal Injection to RC Pump (Loop #1)	N.A.	N.A.
CS-8368B	48	Seal Injection to RC Pump (Loop #2)	N.A.	N.A.
CS-8368C	49	Seal Injection to RC Pump (Loop #3)	N.A.	N.A.
CS-8368D	50	Seal Injection to RC Pump (Loop #4)	N.A.	N.A.
CS-8180	51	Seal Water Return and Excess Letdown	N.A.	C
CT-145	54	Containment Spray to Spray Header (Tr. B)	N.A.	N.A.
CT-142	55	Containment Spray to Spray Header (Tr. A)	N.A.	N.A.
CI-030	62	Instrument Air to Containment	N.A.	C
8841A	63	RHR to Hot Leg Loop #2	N.A.	N.A.
8841B	63	RHR to Hot Leg Loop #3	N.A.	N.A.
SI-8968	104	N_2 Supply to Accumulators	N.A.	C
CA-016	113	Service Air to Containment	N.A.	C
CC-629	117	CC Return From RCP"s Motors	N.A.	C
CC-713	118	CC Supply to RCP"s Motors	N.A.	C
CC-831	119	CC Return From RCP"s Thermal Barrier	N.A.	C
CH-024	120	Chilled Water Supply to Containment Coolers	N.A.	C

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
7. Steam Line Isolation Signal				
HV-2333A	1	Main Steam From Steam Generator #1	5	Notes 2 & 3
HV-2409	3	Drain From Main Steam Line #1	5	N.A.
HV-2334A	6	Main Steam From Steam Generator #2	5	Notes 2 & 3
HV-2410	8	Drain From Main Steam Line #2	5	N.A.
HV-2335A	10	Main Steam From Steam Generator #3	5	Notes 2 & 3
HV-2411	12	Drain From Main Steam Line #3	5	N.A.
HV-2336A	14	Main Steam From Steam Generator #4	5	Notes 2 & 3
HV-2412	16	Drain From Main Steam Line #4	5	N.A.
8. Feedwater Isolation Signal				
HV-2134	19	Feedwater to Steam Generator #1	5	Note 3
FV-2193	20c	Feedwater Preheat Bypass Line S.G. #1	5	Note 3
HV- 2185	20d	Feedwater Bypass Line S.G #1	5	Note 3
HV-2135	21	Feedwater to Steam Generator #2	5	Note 3
FV-2194	22c	Feedwater Preheat Bypass Line S.G. #2	5	Note 3
HV-2186	22d	Feedwater Bypass Line S.G #2	5	Note 3
HV-2136	23	Feedwater to Steam Generator #3	5	Note 3
FV-2195	24c	Feedwater Preheat Bypass Line S.G. #3	5	Note 3
HV-2187	24d	Feedwater Bypass Line S.G #3	5	Note 3
HV-2137	25	Feedwater to Steam Generator #4	5	Note 3
FV-2196	26c	Feedwater Preheat Bypass Line S.G. #4	5	Note 3
HV-2188	26d	Feedwater Bypass Line S.G #4	5	Note 3
9. Safety Injection Actuation Isolation				
8105	46	Charging Line to Regenerative Heat Exchanger	10	C
10. Relief Valves				
8708B	33	RHR From Hot Leg Loop #4	N.A.	N.A.
8708A	34	RHR From Hot Leg Loop #1	N.A.	N.A.

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
MS-021	5b	Main Steam Safety Valve S.G. #1	N.A.	Note 3
MS-022	5b	Main Steam Safety Valve S.G. #1	N.A.	Note 3
MS-023	5b	Main Steam Safety Valve S.G. #1	N.A.	Note 3
MS-024	5b	Main Steam Safety Valve S.G. #1	N.A.	Note 3
MS-025	5b	Main Steam Safety Valve S.G. #1	N.A.	Note 3
MS-058	9b	Main Steam Safety Valve S.G. #2	N.A.	Note 3
MS-059	9b	Main Steam Safety Valve S.G. #2	N.A.	Note 3
MS-060	9b	Main Steam Safety Valve S.G. #2	N.A.	Note 3
MS-061	9b	Main Steam Safety Valve S.G. #2	N.A.	Note 3
MS-062	9b	Main Steam Safety Valve S.G. #2	N.A.	Note 3
MS-093	13b	Main Steam Safety Valve S.G. #3	N.A.	Note 3
MS-094	13b	Main Steam Safety Valve S.G. #3	N.A.	Note 3
MS-095	13b	Main Steam Safety Valve S.G. #3	N.A.	Note 3
MS-096	13b	Main Steam Safety Valve S.G. #3	N.A.	Note 3
MS-097	13b	Main Steam Safety Valve S.G. #3	N.A.	Note 3
MS-129	18b	Main Steam Safety Valve S.G. #4	N.A.	Note 3
MS-130	18b	Main Steam Safety Valve S.G. #4	N.A.	Note 3
MS-131	18b	Main Steam Safety Valve S.G. #4	N.A.	Note 3
MS-132	18b	Main Steam Safety Valve S.G. #4	N.A.	Note 3
MS-133	18b	Main Steam Safety Valve S.G. #4	N.A.	Note 3
RC-036	41a	Penetration Thermal Relief	N.A.	C
WP-7176	52a	Penetration Thermal Relief	N.A.	C
DD-430	60a	Penetration Thermal Relief	N.A.	C
1VD-907 2VD-896	61a	Penetration Thermal Relief	N.A.	C
PS-503	74a	Penetration Thermal Relief	N.A.	C
PS-501	77a	Penetration Thermal Relief	N.A.	C

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS
PS-502	78a	Penetration Thermal Relief	N.A.	C
PS-500	80a	Penetration Thermal Relief	N.A.	C
WP-7177	81a	Penetration Thermal Relief	N.A.	C
1SI-8972 2SI-8983	83a	Penetration Thermal Relief	N.A.	C
1CC-1067 2CC-1090	114a	Penetration Thermal Relief	N.A.	C
1CH-0271 2CH-0281	120a	Penetration Thermal Relief	N.A.	C
1CH-0272 2CH-0282	121a	Penetration Thermal Relief	N.A.	C
SI-0182	125	Pressure Relief for Bonnet of MOV 8811A	N.A.	N.A.
SI-0183	126	Pressure Relief for Bonnet of MOV 8811B	N.A.	N.A.
CT-0309	127	Pressure Relief for Bonnet of MOV HV-4782	N.A.	N.A.
CT-0310	128	Pressure Relief for Bonnet of MOV HV-4783	N.A.	N.A.

Table 13.6.3-1
Containment Isolation Valves

VALVE NO.	FSAR TABLE REFERENCE NO.*	LINE OR SERVICE	MAXIMUM ISOLATION TIME (SECONDS)	NOTES AND LEAK TEST REQUIREMENTS

Table Notations

* Identification code for containment penetration and associated isolation valves in FSAR Tables 6.2.4-1, 6.2.4-2, and 6.2.4-3.

\# May be opened on an intermittent basis under administrative control.

The table does not list local vent, drain and test connections as they are a special class of containment isolation valves and are locked closed to meet containment isolation criteria when located within the penetration boundary. These valves are subject to the same leak rate testing as the other containment isolation valves in the associated penetration, including all applicable leak testing exceptions (see FSAR table 6.2.4-2, including notes). In addition, if these valves are capped (or isolated by blind flange) and under administrative controls they are not required to be leak rate tested. Airlock test connection isolation valves are part of the airlock boundary; therefore, they are subject to the controls of Specification 3.6.2. As such, the requirements of Specification 3.6.3 do not apply.

Note 1: All four MSIV bypass valves are locked closed in Mode 1. During Mode 2, 3, and 4 one MSIV bypass valve may be opened provided the other three MSIV bypass valves are locked closed and their associated MSIVs are closed.

Note 2: These valves require steam to be tested and are thus not required to be tested until the plant is in MODE 3.

Note 3: These valves are included for table completeness; the requirements of Specification 3.6.3 do not apply. Instead, the requirements of Specification 3.7.1, 3.7.2, 3.7.3 and 3.7.4 apply for main steam safety valves, main steam isolation valves, feedwater isolation valves and steam generator atmospheric relief valves, respectively.

Note 4: Not used.

Note 5: 10 CFR 50 Appendix J, Type C testing of these valves is satisfied by the testing of the airlock under Technical Specification Surveillance Requirement 3.6.2.1.

Note 6: These valves are included for table completeness; the requirements of Specification 3.6.3 do not apply. Instead, these valves are considered an integral part of the airlock associated with their respective airlock door. Therefore, they are subject to the controls of Specification 3.6.2.

Note 7: These valves are secured in position by hydraulic system locks and/or interlocks and do not require separate locks.

Note 8: Including the instrumentation delays of the containment ventilation isolation signal from Pressurizer Pressure Low.

Note 9: Upon implementation of FDA-1999-000382-01-00 and acceptance, (1) the requirements for valves HV-2154 and HV-2155 are no longer valid and (2) the requirements for valves FW-113 and FW-116 become effective.

13.6 CONTAINMENT SYSTEMS

TR 13.6.6 Containment Spray System

The performance test requirements for the Containment Spray System pumps subject to SR 3.6.6.4 is as follows:

In the test mode each Containment Spray pump is required to provide a total discharge flow through the test header of greater than or equal to 3300 gpm at 245 psid with the pump eductor line open.

13.7 PLANT SYSTEMS

TR 13.7.31 Steam Generator Atmospheric Relief Valve (ARV) - Air Accumulator Tank

TR LCO 13.7.31 Pursuant to TS 3.7.4, the air accumulator tank for each ARV required to be OPERABLE shall be at a pressure greater than or equal to 80 psig.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Air accumulator tank(s) pressure not within limits.	A.1 Enter the applicable Condition(s) of TS 3.7.4 for affected ARV(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.7.31.1	Verify that the air accumulator tank pressure is within limits.	24 hours

13.7 PLANT SYSTEMS

TR 13.7.32 Steam Generator Pressure / Temperature Limitation

TR LCO 13.7.32 The temperatures of both the primary and secondary coolants in the steam generators shall be greater than 70°F when the pressure of either coolant in the steam generator is greater than 200 psig.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressure / Temperature Limitations not met.	A.1 Reduce the steam generator pressure of the applicable sides to less than or equal to 200 psig.	30 minutes
	AND	
	A.2 Perform an engineering evaluation to determine the effect of the overpressurization on the structural integrity of the steam generator. Determine that the steam generator remains acceptable for continued operation.	Prior to increasing steam generator coolant temperatures above 200 °F

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.7.32.1	- NOTE - Not required to be performed for the associated steam generator when the temperature of both the primary and secondary coolant is > 70 degrees F, or both the primary and secondary coolants are vented and no longer capable of being pressurized. Verify that the pressure in each side of the steam generator is less than 200 psig.	1 hour
TRS 13.7.32.2	- NOTE - Only Required when vent paths for the associated steam generator are being used to meet the LCO. Verify the primary and secondary vent paths are established for the associated steam generator.	24 hours

13.7 PLANT SYSTEMS

TR 13.7.33 Ultimate Heat Sink - Sediment and Safe Shutdown Impoundment (SSI) Dam

TR LCO 13.7.33 The average sediment depth shall be less than or equal to 1.5 feet in the service water intake channel and the SSI dam shall exhibit no abnormal degradation or erosion.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. With the average sediment depth in the service water intake channel greater than 1.5 feet.	A.1 Initiate action in accordance with the Corrective Action Program to remove sediment from the service water intake channel.	Immediately
B. The SSI dam has abnormal degradation or erosion.	B.1 Enter the applicable Condition(s) of TS 3.7.9 for SSI inoperable due to a degraded dam.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.7.33.1	Visually inspect the SSI dam and verify no abnormal degradation or erosion.	12 months
TRS 13.7.33.2	Verify that the average sediment depth in the service water intake channel is less than or equal to 1.5 feet.	12 months

13.7 PLANT SYSTEMS

TR 13.7.34 Flood Protection

TR LCO 13.7.34 Flood protection shall be provided for all safety-related systems, components, and structures when the water level of the Squaw Creek Reservoir (SCR) exceeds 777.5 feet.

- NOTE -
All elevations and SCR water levels in this specification are expressed in feet Mean Sea Level, USGS datum.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------------------------------ - NOTE - Only applicable in MODES 1, 2, 3 and 4. ------------------------------------ Required flood protection measure(s) not in place.	A.1 Initiate action to place the unit in a lower MODE. <u>AND</u> A.2 Be in MODE 3. <u>AND</u> A.3 Be in MODE 4. <u>AND</u> A.4 Be in MODE 5.	1 hours 7 hours 13 hours 37 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.7.34.1	- NOTE - Only required to be performed when SCR water level is < 776 feet. Verify the water level of SCR is measured to be within the limits.	24 hours
TRS 13.7.34.2	- NOTE - Only required to be performed when SCR water level is ≥ 776 feet. Verify the water level of SCR is measured to be within the limits.	2 hours
TRS 13.7.34.3	- NOTE - Only required to be performed when SCR water level is > 777.0 feet. Verify flood protection measures are in effect by verifying that flow paths from the SCR which are open for maintenance are isolated from the SCR by isolation valves, or stop gates, or are at an elevation above 790 feet.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TRS 13.7.34.4	-- - NOTE - Only required to be performed when SCR water level is > 777.5 feet. -- Verify flood protection measures are in effect by verifying that any equipment which is to be opened or is open for maintenance is isolated from the SCR by isolation valves, or stop gates, or is at an elevation above 790 feet.	Once within 2 hours after SCR water level > 777.5 feet <u>AND</u> Prior to opening any equipment for maintenance

13.7 PLANT SYSTEMS

TR 13.7.35 Snubbers

TR LCO 13.7.35 All snubbers shall be OPERABLE. The only snubbers excluded from the requirements are (1) those installed on nonsafety-related systems and then only if their failure or failure of the system on which they are installed would have no adverse effect on any safety-related system or (2) those snubber(s) that have an evaluation which determines that the supported TS system(s) do not require the snubber(s) to be functional in order to support the OPERABILITY of the system(s).

APPLICABILITY: MODES 1, 2, 3, and 4. MODES 5 and 6 for snubbers located on systems required OPERABLE in those MODES.

- NOTE -

While this LCO is not met, MODE changes shall be restricted to those MODE changes allowed by the applicable LCO's for the equipment which may be potentially inoperable as a result of the inoperable snubber(s).

ACTIONS

- NOTE -

Separate Condition entry allowed for each snubber.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more snubbers inoperable.	A.1 Enter the operability determination process for attached system(s). <u>AND</u> A.2 Perform an engineering evaluation in accordance with the approved snubber augmented inservice inspection program on the attached component.	Immediately 72 hours

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.7.35.1	Each required snubber shall be demonstrated OPERABLE by performance of the requirements of the approved snubber augmented inservice inspection program in TR 15.5.31.	Per snubber augmented inservice inspection program.

13.7 PLANT SYSTEMS

TR 13.7.36 Area Temperature Monitoring

TR LCO 13.7.36 The maximum temperature limit for normal conditions of each area shown in Table 13.7.36-1 shall not be exceeded for more than 8 hours and the maximum temperature limit for abnormal conditions of each area given in Table 13.7.36-1 shall not be exceeded.

APPLICABILITY: Whenever the equipment in an affected area is required to be OPERABLE.

- NOTE -
While this LCO is not met due to exceeding the maximum temperature limit for abnormal conditions, MODE changes shall be restricted to those allowed by the applicable LCOs for the equipment which may be potentially inoperable due to exceeding the limit for abnormal conditions.

ACTIONS

- NOTE -
Separate condition entry is allowed for each area listed in Table 13.7.36-1.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more areas exceeds the maximum temperature limit(s) for normal conditions shown in Table 13.7.36-1 for more than 8 hours.	----------- - NOTE - Required Action must be completed whenever Condition A is entered. -----------	
	A.1 Initiate action in accordance with the Corrective Action Program to restore the temperature(s) to within normal limits, including an analysis to demonstrate the continued OPERABILITY of the affected equipment.	Immediately

(continued)

ACTIONS (continued)

B. One or more areas exceeds the maximum temperature limit(s) for abnormal conditions shown in Table 13.7.36-1.	B.1.1 Restore the area(s) to within the maximum temperature limit(s) for abnormal conditions.	4 hours
	<u>OR</u>	
	B.1.2.1 Enter the appropriate Condition(s) of the appropriate TS(s) for the equipment in the affected area(s) inoperable.	4 hours
	<u>OR</u>	
	B.1.2.2.1 Perform a review of the qualification envelope for the affected equipment.	4 hours
	<u>AND</u>	
	B.1.2.2.2 Declare INOPERABLE any affected equipment in a qualification envelope that has been exceeded.	4 hours
	<u>OR</u>	
	B.1.3 Perform an analysis that justifies continued operation.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.7.36.1	Verify the temperature in each of the areas shown in Table 13.7.36-1 to be within limit(s).	12 hours

Table 13.7.36-1
Area Temperature Monitoring

AREA	MAXIMUM TEMPERATURE LIMIT (°F)	
	NORMAL CONDITIONS	ABNORMAL CONDITIONS
1. Electrical and Control Building		
Normal Areas	104	131
Control Room Main Level (El. 830'-0")	80	104
Control Room Technical Support Area (El. 840'-6")	104	104
UPS/Battery Rooms	104	113
Chiller Equipment Areas	122	131
2. Fuel Building		
Normal Areas	104	131
Spent Fuel Pool Cooling Pump Rooms	122	131
3. Safeguards Buildings		
Normal Areas	104	131
AFW, RHR, SI, Containment Spray Pump Rooms	122	131
RHR Valve and Valve Isolation Tank Rooms	122	131
RHR/CT Heat Exchanger Rooms	122	131
Diesel Generator Area	122	131
Diesel Generator Equipment Rooms	130	131
Day Tank Room	122	131
4. Auxiliary Building	127	131
Normal Areas	104	131
CCW, CCP Pump Rooms	122	131
CCW Heat Exchanger Area	122	131
CVCS Valve and Valve Operating Rooms	122	131
Auxiliary Steam Drain Tank Equip. Room	122	131
Waste Gas Tank Valve Operating Room	122	131
5. Service Water Intake Structure	127	131
6. Containment Buildings		
General Areas	120	129
Reactor Cavity Exhaust	150	190
CRDM Shroud Exhaust	163	172

13.7 PLANT SYSTEMS

TR 13.7.37 Safety Chilled Water System - Electrical Switchgear Area Emergency Fan Coil Units

TR LCO 13.7.37 The safety chilled water system electrical switchgear area emergency fan coil units shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required electrical switchgear area emergency fan coil unit(s) inoperable.	A.1 Declare Safety Chilled Water train(s) inoperable (TS 3.7.19).	Immediately
	OR	
	A.2 Declare affected fan coil unit(s) and their supported equipment inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.7.37.1	Verify electrical switchgear area emergency fan coil units start on an actual or simulated Safety Injection actuation signal.	18 months

13.7 PLANT SYSTEMS

TR 13.7.38 Main Feedwater Isolation Valve Pressure / Temperature Limit

TR LCO 13.7.38 The valve body and neck of each main feedwater isolation valve shall be greater than or equal to 90°F, when feedwater line pressure is greater than 675 psig.

APPLICABILITY: MODES 1, 2, 3 and during pressure testing of the steam generator or main feedwater line.

ACTIONS

- NOTE -

Separate Condition entry allowed for each main feedwater isolation valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more main feedwater isolation valves outside of the required limits.	A.1 Restore main feedwater isolation valve(s) pressure and/or temperature to within limits.	1 hour
	<u>AND</u>	
	A.2 -- - NOTE - Required Action A.2 must be completed whenever Condition A is entered. -- Perform an engineering evaluation to determine the effect of the overpressure on the structural integrity of the main feedwater isolation valve(s) and determine that the main feedwater isolation valve(s) remains acceptable for continued operation.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Actions and associated Completion Times of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.7.38.1	--- - NOTE - Not required to be performed in MODE 1 with the main feedwater isolation valve open. --- Each main feedwater isolation valve shall be determined to be greater than or equal to 90°F.	12 hours

13.7 PLANT SYSTEMS

TR 13.7.39 Tornado Missile Shields

TR LCO 13.7.39 Required equipment shall be protected from tornado generated missiles as required by Allowances of Table 13.7.39-1.

APPLICABILITY: Whenever supported equipment is required to be OPERABLE.

- NOTE -

Only applicable if any required missile shield is not in its missile protection configuration.

ACTIONS

- NOTE -

Separate Condition entry allowed for each missile shield.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Allowances of Table 13.7.39-1 not met for one or more missile shields.	A.1 Declare equipment supported by affected missile shield(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.7.39.1	Verify allowances of Table 13.7.39-1 are satisfied.	Prior to removal of any missile shield

Table 13.7.39-1
Missile Shield Allowances

Shields: S1-27 Door, Unit 1 Safeguards Corridor El. 810' 6"

Related Specifications: 3.7.12

Allowance:

1. Unit 1 and 2 in MODES 5 and 6, or Unit 1 in MODES 5 and 6 and the Unit 1 Safeguards Bldg. is NOT in Direct Communication with the Unit 2 Primary Plant Ventilation Pressure Boundary.

   a. May be open under administrative control provided the capability to close immediately on notification of a Tornado Warning exist.

   b . May be removed under administrative control provided the capability exists to reinstall immediately on notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES.

2. Unit 1 in MODES 5 and 6, Unit 2 in MODES 1, 2, 3 and 4, and the Unit 1 Safeguards Bldg. is in Direct Communication with the Unit 2 Primary Plant Ventilation Pressure Boundary.

   a. May be open under administrative control provided:

      - Unit 2 enters LCO 3.7.12 CONDITION B, and
      - It is continuously manned, with direct communications established to the control room, and
      - It is capable of immediate closure upon notification from the Control Room of a Tornado Warning or Unit 2 Safety Injection.

   b. May be removed under administrative control provided:

      - Unit 2 enters LCO 3.7.12 CONDITION B, and
      - The capability exists to re-install immediately on notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES.

3. Unit 1 and 2 in MODES 1, 2, 3 and 4.

   May be open under administrative control for up to 72 hours provided:

   a. Units 1 and 2 enter LCO 3.7.12 CONDITION B, and

   b. It is continuously manned, with direct communications established to the control room, and

   c. It is capable of immediate closure upon notification from the Control Room of a Tornado Warning, Unit 1 Safety Injection or Unit 2 Safety Injection.

Table 13.7.39-1
Missile Shield Allowances

Shields: S2-27 Door, Unit 2 Safeguards Corridor El. 810' 6"

Related Specifications: 3.7.12

Allowance:

1. Unit 1 and 2 in MODES 5 and 6, or Unit 2 in MODES 5 and 6 and the Unit 2 Safeguards Bldg. is NOT in Direct Communication with the Unit 1 Primary Plant Ventilation Pressure Boundary.

    a. May be open under administrative control provided the capability to close immediately on notification of a Tornado Warning exist.

    b. May be removed under administrative control provided the capability exists to reinstall immediately on notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES.

2. Unit 2 in MODES 5 and 6, Unit 1 in MODES 1, 2, 3 and 4, and the Unit 2 Safeguards Bldg. is in Direct Communication with the Unit 1 Primary Plant Ventilation Pressure Boundary.

    a. May be open under administrative control provided:

        - Unit 1 enters LCO 3.7.12 CONDITION B, and
        - It is continuously manned, with direct communications established to the control room, and
        - It is capable of immediate closure upon notification from the Control Room of a Tornado Warning or Unit 1 Safety Injection.

    b. May be removed under administrative control provided:

        - Unit 1 enters LCO 3.7.12 CONDITION B, and
        - The capability exists to re-install immediately on notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES.

3. Unit 1 and 2 in MODES 1, 2, 3 and 4.

    May be open under administrative control for up to 72 hours provided:

    a. Units 1 and 2 enter LCO 3.7.12 CONDITION B, and

    b. It is continuously manned, with direct communications established to the control room, and

    c. It is capable of immediate closure upon notification from the Control Room of a Tornado Warning, Unit 1 Safety Injection or Unit 2 Safety Injection.

Table 13.7.39-1
Missile Shield Allowances

Shields: S1-38B Door, Auxiliary Bldg. El. 852' 6'
S1 -38D Door, Train B Electrical Equipment Area

Related Specifications: 3.7.12 (S1-38B only); 3.8.9 (S-38D only)

Allowance:

1. Unit 1 and 2 in MODES 5 and 6, or Unit 1 in MODES 5 and 6 and the Unit 1 Safeguards Bldg. is NOT in Direct Communication with the Unit 2 Primary Plant Ventilation Pressure Boundary.

   a. May be open under administrative control provided the capability to close immediately on notification of a Tornado Warning exist.

   b. May be removed under administrative control provided the capability exists to reinstall immediately on notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES.

2. Unit 1 in MODES 5 and 6, Unit 2 in MODES 1, 2, 3 and 4, and the Unit 1 Safeguards Bldg. is in Direct Communication with the Unit 2 Primary Plant Ventilation Pressure Boundary.

   a. May be open under administrative control provided:

      - It is continuously manned, with direct communications established to the control room, and
      - It is capable of immediate closure upon notification from the Control Room of a Tornado Warning or Unit 2 Safety Injection.

   b. May be removed under administrative control provided:

      - Unit 2 enters LCO 3.7.12 CONDITION B, and
      - The capability exists to re-install immediately on notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES.

3. Unit 1 and 2 in MODES 1, 2, 3 and 4.

   May be open under administrative control for up to 72 hours provided:

   a. It is continuously manned, with direct communications established to the control room, and

   b. It is capable of immediate closure upon notification from the Control Room of a Tornado Warning, Unit 1 Safety Injection or Unit 2 Safety Injection.

Table 13.7.39-1
Missile Shield Allowances

Shields: S2-38B Door, Auxiliary Bldg. El. 852' 6"
S2-38D Door, Train B Electrical Equipment Area

Related Specifications: 3.7.12 (S2-38B only); 3.8.9 (S-38D only)

Allowance:

1. Unit 1 and 2 in MODES 5 and 6, or Unit 2 in MODES 5 and 6 and the Unit 2 Safeguards Bldg. is NOT in Direct Communication with the Unit 1 Primary Plant Ventilation Pressure Boundary.

    a. May be open under administrative control provided the capability to close immediately on notification of a Tornado Warning exist.

    b. May be removed under administrative control provided the capability exists to reinstall immediately on notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES.

2. Unit 2 in MODES 5 and 6, Unit 1 in MODES 1, 2, 3 and 4, and the Unit 2 Safeguards Bldg. is in Direct Communication with the Unit 1 Primary Plant Ventilation Pressure Boundary.

    a. May be open under administrative control provided:

        - It is continuously manned, with direct communications established to the control room, and
        - It is capable of immediate closure upon notification from the Control Room of a Tornado Warning or Unit 1 Safety Injection.

    b. May be removed under administrative control provided:

        - Unit 1 enters LCO 3.7.12 CONDITION B, and
        - The capability exists to re-install immediately on notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES.

3. Unit 1 and 2 in MODES 1, 2, 3 and 4.

    May be open under administrative control for up to 72 hours provided:

    a. It is continuously manned, with direct communications established to the control room, and

    b. It is capable of immediate closure upon notification from the Control Room of a Tornado Warning, Unit 1 Safety Injection or Unit 2 Safety Injection.

Table 13.7.39-1
Missile Shield Allowances

Shields: Access Cover Plates (4) El. 852' 6", above Unit 1 Safeguard Bldg. Corridor

Related Specifications: 3.4.7*, 3.4.8*, 3.7.12, 3.9.5*, and 3.9.6*.

Allowance:

1. Unit 1 and 2 in MODES 5 and 6, or Unit 1 in MODES 5 and 6 and the Unit 1 Safeguards Bldg. is NOT in Direct Communication with the Unit 2 Primary Plant Ventilation Pressure Boundary. May be removed under administrative control provided either:

    a. The floor plugs (El. 831' 6" corridor) over each OPERABLE Unit 1 RHR heat exchanger are in place, or

    b. The capability exists to re-install the missile shield or floor plugs immediately upon notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES. If only one RHR system is OPERABLE, either its missile shield or floor plug shall be in place.

2. Unit 1 in MODES 5 and 6, Unit 2 in MODES 1, 2, 3 and 4, and the Unit 1 Safeguards Bldg. is in Direct Communication with the Unit 2 Primary Plant Ventilation Pressure Boundary. May be removed under administrative control provided:

    a. Unit 2 enters LCO 3.7.12 CONDITION B, and either

        - The floor plugs (El. 831' 6" corridor) over each OPERABLE Unit 1 RHR heat exchanger are in place, or
        - The capability exists to re-install the missile shield or floor plugs immediately upon notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES. If only one RHR system is OPERABLE, either its missile shield or floor plug shall be in place.

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*Only affects RHR operability

Table 13.7.39-1
Missile Shield Allowances

Shields: Access Cover Plates (4) El. 852' 6", above Unit 2 Safeguard Bldg. Corridor

Related Specifications: 3.4.7*, 3.4.8*, 3.7.12, 3.9.5*, and 3.9.6*.

Allowance:

1. Unit 1 and 2 in MODES 5 and 6, or Unit 2 in MODES 5 and 6 and the Unit 2 Safeguards Bldg. is NOT in Direct Communication with the Unit 1 Primary Plant Ventilation Pressure Boundary. May be removed under administrative control provided either:

   a. The floor plugs (El. 831' 6" corridor) over each OPERABLE Unit 2 RHR heat exchanger are in place, or

   b. The capability exists to re-install the missile shield or floor plugs immediately upon notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES. If only one RHR system is OPERABLE, either its missile shield or floor plug shall be in place.

2. Unit 2 in MODES 5 and 6, Unit 1 in MODES 1, 2, 3 and 4, and the Unit 2 Safeguards Bldg. is in Direct Communication with the Unit 1 Primary Plant Ventilation Pressure Boundary. May be removed under administrative control provided:

   a. Unit 1 enters LCO 3.7.12 CONDITION B, and either

      - The floor plugs (El. 831' 6" corridor) over each OPERABLE Unit 2 RHR heat exchanger are in place, or

      - The capability exists to re-install the missile shield or floor plugs immediately upon notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES if only one RHR system is OPERABLE, either its missile shield or floor plug shall be in place.

---

*Only affects RHR operability

Table 13.7.39-1
Missile Shield Allowances

Shields: E-40A Door, Control Room

Related Specifications: 3.7.10

Allowance:

In all MODES may be open under administrative control for up to 72 hours provided:

a. It is continuously manned, with direct communications established to the control room, and

b. It is capable of immediate closure upon notification from the Control Room (of a Tornado Warning, Safety Injection, Loss-of-Offsite Power, or Intake Vent-High Radiation).

Shields: Unit 1 Containment Equipment Hatch Missile Shield (Outer Cover)*

Related Specifications: 3.6.6

Allowance:

Unit 1 in MODES 1, 2, 3 and 4.

May be removed in MODE 4 for up to 72 hours provided the capability exists to immediately reinstall the missile shield upon notification of a National Weather Service issued Tornado Warning, Tornado Watch or other special Weather Statement with winds in excess of 60 mph affecting CPSES.

Not required in MODES 5, 6 or Defueled.

Shields: Unit 2 Containment Equipment Hatch Missile Shield (Outer Cover)*

Related Specifications: 3.6.6

Allowance:

Unit 2 in MODES 1, 2, 3 and 4.

May be removed in MODE 4 for up to 72 hours provided the capability exists to immediately reinstall the missile shield upon notification of a National Weather Service issued Tornado Warning, Tornado Watch or other special Weather Statement with winds in excess of 60 mph affecting CPSES.

Not required in MODES 5, 6 or Defueled.

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* The Inner cover of the Equipment Hatch is considered part of the containment liner and is addressed in accordance with LCO 3.6.1, “Containment.”

Table 13.7.39-1
Missile Shield Allowances

Shields:	Related Specifications:
Access Cover Plate, Unit 1 Diesel FO Truck Fill Station	3.8.1, 3.8.2
Access Cover, Unit 1 RWST	None
Access Cover, Unit 1 CST	3.7.6
Access Cover, Unit 1 RMWST	None
Service Water Tunnel, Manhole Cover (Common) El. 810' 6"	3.7.8
Removable Slab (Hatch Cover), Electric Fire Pumps CPX-FPAPFP-01 AND CPX-FPAPFP-03	3.7.8
Access Cover Plate, Unit 2 Diesel FO Truck Fill Station	3.8.1, 3.8.2
Access Cover, Unit 2 RWST	None
Access Cover, Unit 2 CST	3.7.6
Access Cover, Unit 2 RMWST	None

Allowance:

May be removed under administrative control provided the capability exists to re-install the missile shield immediately upon notification of a National Weather Service Issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES.

Table 13.7.39-1
Missile Shield Allowances

Shields:	Related Specifications:
Cover Plates (2), Unit 1 Diesel FO Storage Tanks	3.8.1, 3.8.2
Access Cover Plates (2), Unit 1 Diesel FO Storage Tanks	3.8.1, 3.8.2
Removable Slab SW Piping (Unit 1/2 Train B) El. 810' 6"	3.7.8
Removable Slab (Hatch Cover) SW Pump, CP1-SWAPSW-02	3.7.8
Removable Slab (Hatch Cover) SW Pump, CP1-SWAPSW-01	3.7.8
Manhole Cover, MH#E1A1, Unit 1 SW Train A	3.7.8
Manhole Cover, MH#E1A2, Unit 1 SW Train A	3.7.8
Manhole Cover, MH#E1B1, Unit 1 SW Train B	3.7.8
Manhole Cover; MH#E1B2, Unit 1 SW Train B	3.7.8
Cover Plates (2), Unit 2 Diesel FO Storage Tanks	3.8.1, 3.8.2
Access Cover Plates (2), Unit 2 Diesel FO Storage Tanks	3.8.1, 3.8.2
Removable Slab (Hatch Cover) SW Pump, CP2-SWAPSW-02	3.7.8
Removable Slab (Hatch Cover) SW Pump, CP2-SWAPSW-01	3.7.8
Manhole Cover, MH#E2A1, Unit 2 SW Train A	3.7.8
Manhole Cover, MH#E2A2, Unit 2 SW Train A	3.7.8
Manhole Cover, MH#E2A3, Unit 2 SW Train A	3.7.8
Manhole Cover, MH#E2A4, Unit 2 SW Train A	3.7.8
Manhole Cover, MH#E2A5, Unit 2 SW Train A	3.7.8
Manhole Cover, MH#E2B1, Unit 2 SW Train B	3.7.8
Manhole Cover, MH#E2B2, Unit 2 SW Train B	3.7.8
Manhole Cover, MH#E2B3, Unit 2 SW Train B	3.7.8
Manhole Cover, MH#E2B4, Unit 2 SW Train B	3.7.8
Manhole Cover, MH#E2B5, Unit 2 SW Train B	3.7.8

Allowance:

May be removed under administrative control for up to 72 hours provided:

a. The capability exists to re-install the missile shield immediately upon notification of a National Weather Service issued Tornado Warning, Tornado Watch, or other Special Weather Statement with winds in excess of 60 mph affecting CPSES, and

b. No more than one OPERABLE train per unit of a system shall have its missile shields removed at one time.

13.7 PLANT SYSTEMS

TR 13.7.41 Condensate Storage Tank (CST) Make-up and Reject Line Isolation Valves

TR LCO 13.7.41 Two CST make-up and reject line isolation valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3, except when the CST make-up and reject line is isolated by a closed and de-activated isolation valve.

ACTIONS

- NOTE -
The make-up and reject line may be unisolated intermittently under administrative controls.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CST make-up and reject line isolation valve inoperable.	A.1 Isolate the make-up and reject line. AND A.2 Verify the flowpath is isolated.	72 hours Once per 31 days
B. Two CST make-up and reject line isolation valves inoperable.	B.1 Isolate the make-up and reject line.	4 hours

(continued)

ACTIONS (continued)

C. Required Actions and associated Completion Times for Conditions A or B not met.	C.1 Verify by administrative means OPERABILITY of backup water supply. AND C.2 Restore both affected valves to OPERABLE.	4 hours AND Once per 12 hours thereafter 7 days

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.7.41.1	Verify each CST make-up and reject line isolation valve actuates to the isolation position on an actual or simulated actuation signal.	18 months
TRS 13.7.41.2	Verify a make-up and reject line isolation actuation signal is initiated on CST HI-HI level.	18 months

13.8 ELECTRICAL POWER SYSTEMS

TR 13.8.31 AC Sources (Diesel Generator Requirements)

TR LCO 13.8.31 Pursuant to TS 3.8.1 and 3.8.2, the Technical Requirements Surveillances (TRS) listed below for the diesel generator(s) (DGs) required to be capable of supplying the onsite Class 1E power distribution subsystem(s) shall be met.

APPLICABILITY: MODES 1, 2, 3, 4, 5 and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the following surveillances not met for required DG(s).	A.1 Enter the applicable Condition(s) of TS 3.8.1 or 3.8.2 for the effected DG(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.8.31.1	Verify diesel generator is aligned to provide standby power to the associated emergency busses.	31 days
TRS 13.8.31.2	-------------------- - NOTE - Verify requirement during MODES 3, 4, 5, 6, or with core off-loaded. -------------------- Subject the diesel to inspections in accordance with procedures prepared in conjunction with the diesel owners group's preventive maintenance program.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TRS 13.8.31.3	--- - NOTE - Verify requirement during MODES 3, 4, 5, 6, or with core off-loaded. --- Verify that the auto-connected loads to each diesel generator do not exceed the continuous rating of 7,000 kW.	18 months
TRS 13.8.31.4	--- - NOTE - Verify requirement during MODES 3, 4, 5, 6, or with core off-loaded. --- Verify that the following diesel generator lockout features prevent diesel generator from starting: a. Barring device engaged, or b. Maintenance Lockout Mode.	18 months
TRS 13.8.31.5	Pump out each fuel oil storage tank, remove accumulated sediment and clean the tank using a sodium hypochlorite solution or equivalent.	10 Years
TRS 13.8.31.6	Perform a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code, when tested pursuant to the Inservice Inspection Program.	10 Years

13.8 ELECTRICAL POWER SYSTEMS

TR 13.8.32 Containment Penetration Conductor Overcurrent Protection Devices

TR LCO 13.8.32 All containment penetration conductor overcurrent protective devices, which are listed in Table 13.8.32-1, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTIONS

- NOTES -

1. TR LCO 13.0.4.c is applicable to overcurrent protective devices in circuits which have their associated protective device tripped/removed and their inoperable protective device racked out, locked open, or removed.

2. Separate Condition entry is allowed for each overcurrent protection device.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more of the containment penetration conductor overcurrent protective device(s) inoperable.	A.1.1.1 Verify the circuit(s) de-energized by racked out, locked open, or removed inoperable protective device(s).	72 hours AND Once per 31 days thereafter
	AND	
	A.1.1.2 Tripping/ removing the associated protective device(s).	72 hours
	OR	
	A.1.2.1 Verify the circuit(s) de-energized by tripped/removed associated protective device(s).	72 hours AND Once per 7 days thereafter
	OR	
	A.1.2.2 Verify the circuit(s) de-energized by racked out, locked open, or removed inoperable protective device(s).	72 hours AND Once per 7 days thereafter
	AND	
	A.2 Declare the affected system(s) or component(s) inoperable.	72 hours
B. Required Actions and associated Completion Times not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE			FREQUENCY
TRS 13.8.32.1	Verify that the medium voltage 6.9 kV and low voltage 480V switchgear circuit breakers are OPERABLE by:		72 months AND
	a.	A CHANNEL CALIBRATION of the associated protective relays,	At least 10% of the breakers of a group tested every 18 months
	b.	An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and control circuits function as designed, and	
	c.	For each circuit breaker found inoperable during these functional tests, one or 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.	

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TRS 13.8.32.2	Verify that the 480V and lower voltage molded case circuit breakers are OPERABLE by performing the following: a. Inverse time overcurrent trip test to verify that the test trip time does not exceed the maximum trip time per the breaker time-current characteristics. b. Instantaneous overcurrent trip test. c. Circuit breakers found inoperable during functional testing shall be replaced by OPERABLE breakers prior to resuming operation. d. 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.	72 months <u>AND</u> At least 10% of the breakers tested every 18 months for breaker groups with ≥4 breakers <u>OR</u> At least 1 breaker tested every 36 months for breakers groups with 2 or 3 breakers.
TRS 13.8.32.3	Subject each medium voltage 6.9kv switchgear circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.	60 months
TRS 13.8.32.4	Subject each low voltage 480V switchgear circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.	60 months
TRS 13.8.32.5	Subject each 480V and lower voltage molded case switchgear circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.	72 months

Table 13.8.32-1a (Page 1 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1. 6.9 KVAC from Switchgears	
a. Switchgear Bus 1A1	RCP #11
1) Primary Breaker 1PCPX1	
a) Relay 50M1-51	
b) Relay 86M	
2) Backup Breakers 1A1-1 or 1A1-2	
a) Relay 51M3	
b) Relay 51 for 1A1-1	
c) Relay 51 for 1A1-2	
d) Relay 86/1A1	
b. Switchgear Bus 1A2	RCP #12
1) Primary Breaker 1PCPX2	
a) Relay 50M1-51	
b) Relay 86M	
2) Backup Breakers 1A2-1 or 1A2-2	
a) Relay 51M3	
b) Relay 51 for 1A2-1	
c) Relay 51 for 1A2-2	
d) Relay 86/1A2	

Table 13.8.32-1a (Page 2 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
c. Switchgear Bus 1A3	RCP #13
1) Primary Breaker 1PCPX3	
a) Relay 50M1-51	
b) Relay 86M	
2) Backup Breakers 1A3-1 or 1A3-2	
a) Relay 51M3	
b) Relay 51 for 1A3-1	
c) Relay 51 for 1A3-2	
d) Relay 86/1A3	
d. Switchgear Bus 1A4	RCP #14
1) Primary Breaker 1PCPX4	
a) Relay 50M1-51	
b) Relay 86M	
2) Backup Breaker 1A4-1 or 1A4-2	
a) Relay 51M3	
b) Relay 51 for 1A4-1	
c) Relay 51 for 1A4-2	
d) Relay 86/1A4	

Table 13.8.32-1a (Page 3 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2. 480 VAC from Switchgears	
2.1 480V Switchgear 1EB1	
1. Compartment 3B	Containment Recirc Fan CP1-VAFNAV-01
a) Primary Breaker 1FNAV1	
1) Relay: Amptector Trip Unit of Breaker 1FNAV1	
b) Backup Breakers 1EB1-1 and BT-1EB13	
1) Long Time and Instantaneous Relay $\frac{50-51}{1FNAV1}$	
2) Time Delay Relay $\frac{62-1}{1FNAV1}$	
2.2 480V Switchgear 1EB2	
1. Compartment 3B	Containment Recirc Fan CP1-VAFNAV-02
a) Primary Breaker 1FNAV2	
1) Relay: Amptector Trip Unit of Breaker 1FNAV2	
b) Backup Breakers 1EB2-1 and BT-1EB24	
1) Long Time and Instantaneous Relay $\frac{50-51}{1FNAV2}$	
2) Time Delay Relay $\frac{62-1}{1FNAV2}$	
2.3 480V Switchgear 1EB3	
1. Compartment 8B	CRDM Vent Fan CP1-VAFNCB-01
a) Primary Breaker 1FNCB1	
1) Relay: Amptector Trip Unit of Breaker 1FNCB1	
b) Backup Breakers 1EB3-1 and BT-1EB13	
1) Long Time and Instantaneous Relay $\frac{50-51}{1FNCB1}$	
2) Time Delay Relay $\frac{62-1}{1FNCB1}$	

Table 13.8.32-1a (Page 4 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2. Compartment 9B	Containment Recirc Fan CP1-VAFNAV-03
a) Primary Breaker 1FNAV3	
1) Relay: Amptector Trip Unit of Breaker 1FNAV3	
b) Backup Breakers 1EB3-1 and BT-1EB13	
1) Long Time and Instantaneous Relay $\frac{50-51}{1FNAV3}$	
2) Time Delay Relay $\frac{62-1}{1FNAV3}$	
2.4 480V Switchgear 1EB4	
1. Compartment 8B	CRDM Vent Fan CP1-VAFNCB-02
a) Primary Breaker 1FNCB2	
1) Relay: Amptector Trip Unit of Breaker 1FNCB2	
b) Backup Breakers 1EB4-1 and BT-1EB24	
1) Long Time and Instantaneous Relay $\frac{50-51}{1FNCB2}$	
2) Time Delay Relay $\frac{62-1}{1FNCB2}$	
2. Compartment 9B	Containment Recirc Fan CP1-VAFNAV-04
a) Primary Breaker 1FNAV4	
1) Relay: Amptector Trip Unit of Breaker 1FNAV4	
b) Backup Breakers 1EB4-1 and BT-1EB24	
1) Long Time and Instantaneous Relay $\frac{50-51}{1FNAV4}$	
2) Time Delay Relay $\frac{62-1}{1FNAV4}$	

Table 13.8.32-1a (Page 5 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED

3. 480VAC from Motor Control Centers

3.1 Device Location - MCC 1EB1-2 Compartment Numbers listed below.

Primary and Backup Breakers - Both primary and backup breakers have identical trip ratings and are in the same MCC Compt. These breakers are General Electric type THED with thermal-magnetic trip elements.

MCC 1EB1-2 COMPT. NO.	G.E. BKR. TYPE	SYSTEM POWERED
4G	THED	Motor Operated Valve 1-TV-4691
4M	THED	Motor Operated Valve 1-TV-4693
3F	THED	Containment Drain Tank Pump-03
9H	THED	Reactor Cavity Sump Pump-01
9M	THED	Reactor Cavity Sump Pump-02
7H	THED	Containment Sump #1 Pump-01
7M	THED	Containment Sump #1 Pump-02
6H	THED	RCP #11 Motor Space Heater-01
6M	THED	RCP #13 Motor Space Heater-03
8B	THED	Incore Detector Drive "A"
8D	THED	Incore Detector Drive "B"
7B	THED	Incore Detector Drive "F"
3B	THED	Stud Tensioner Hoist Outlet-01
7D	THED	Hydraulic Deck Lift-01
4B	THED	Reactor Coolant Pump Motor Hoist Receptacle-42
8H	THED	RC Pipe Penetration Cooling Unit-01
8M	THED	RC Pipe Penetration Cooling Unit-02
5H	THED	RCP #11 Oil Lift Pump-01
5M	THED	RCP #13 Oil Lift Pump-03
10B	THED	Preaccess Filter Train Package Receptacle-17
10F	THED	S.G. Wet Layup Circ. Pump 01 (CP1-CFAPRP-01)
12M	THED	S.G. Wet Layup Circ. Pump 03 (CP1-CFAPRP-03)
12H	THED	Containment Ltg. XFMR-28 (PNL C11 & C12)
2M	THED	RC Drain Tank Pump No. 1
2F	THED	Containment Ltg. XFMR-16 (PNL C7 & C9)
1M	THED	Containment Ltg. XFMR-12 (PNL C1 & C5)
3M	THED	Preaccess Fan No. 11

Table 13.8.32-1a (Page 6 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION			SYSTEM POWERED
3.2	Device Location	-	MCC 1EB2-2 Compartment Numbers listed below.
	Primary and Backup Breakers	-	Both primary and backup breakers have identical trip ratings and are located in the same MCC compt. These breakers are General Electric type THED with thermal-magnetic trip elements.

MCC 1EB2-2 COMPT. NO.	G.E. BKR. TYPE	SYSTEM POWERED
4G	THED	Motor Operated Valve 1-TV-4692
4M	THED	Motor Operated Valve 1-TV-4694
3F	THED	Containment Drain Tank Pump-04
7H	THED	Containment Sump No. 2 Pump-03
7M	THED	Containment Sump No. 2 Pump-04
6H	THED	RCP #12 Motor Space Heater-02
6M	THED	RCP #14 Motor Space Heater-04
5B	THED	Incore Detector Drive "C"
2B	THED	Incore Detector Drive "D"
7B	THED	Incore Detector Drive "E"
5D	THED	Containment Fuel Storage Crane-01
3B	THED	Stud Tensioner Hoist Outlet-02
4B	THED	Containment Solid Rad Waste Compactor-01
10B	THED	RCC Change Fixture Hoist Drive-01
10F	THED	Refueling Cavity Skimmer Pump-01
12B	THED	Power Receptacles (Cont. E1. 841')
1M	THED	S.G. Wet Layup Circ. Pump 02 (CP1-CFAPRP-02)
12M	THED	S.G. Wet Layup Circ. Pump 04 (CP1-CFAPRP-04)
8H	THED	RC Pipe Penetration Fan-03
8M	THED	RC Pipe Penetration Fan-04
5H	THED	RCP #12 Oil Lift Pump-02
5M	THED	RCP #14 Oil Lift Pump-04
12H	THED	Preaccess Filter Train Package Receptacles - 18
6D	THED	Containment Auxiliary Upper Crane-01[a]
2F	THED	Containment Ltg. XFMR-13 (PNL C2)
2D	THED	Containment Access Rotating Platform-01
2M	THED	Reactor Coolant Drain Tank Pump-02
9F	THED	Containment Ltg. XFMR-17(PNL C8 & C10)
9M	THED	Containment Ltg. XFMR-15 (PNL C4 & C6)
3M	THED	Preaccess Fan-12

(a) Upon implementation and acceptance by Operations of FDA-2002-001062-01; the System Powered is changed from “Containment Auxiliary Upper Crane –01” to “Containment Building Welding Receptacle El. 905’-9””.

Table 13.8.32-1a (Page 7 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
3.3 Device Location -	MCC 1EB3-2 Compartment numbers listed below.
Primary and Backup Breakers -	Unless noted otherwise, both primary and backup breakers have identical trip ratings and are located in the same MCC compt. These breakers are General Electric type THED or THFK with thermal-magnetic trip elements.

MCC 1EB3-2 COMPT. NO.	G.E. BKR. TYPE	SYSTEM POWERED
8RF	THED	JB-1S-10050, Altern. Feed to Motor Operated Valve 1-8702A
1G	THED	Motor Operated Valve 1-8112
9G	THED	Motor Operated Valve 1-8701A
9M	THED	Motor Operated Valve 1-8701B
5M	THED	Motor Operated Valve 1-8000A
5G	THED	Motor Operated Valve 1-HV-6074
4G	THED	Motor Operated Valve 1-HV-6076
4M	THED [(a)]	Motor Operated Valve 1-HV-6078
2G	THED	Motor Operated Valve 1-HV-4696
2M	THED	Motor Operated Valve 1-HV-4701
3G	THED [(a)]	Motor Operated Valve 1-HV-5541
3M	THED [(a)]	Motor Operated Valve 1-HV-5543
1M	THED	Motor Operated Valve 1-HV-6083
6F	THED	Motor Operated Valve 1-8808A
6M	THED	Motor Operated Valve 1-8808C
7M	THED	Containment Ltg. XFMR-18 (PNL SC1 & SC3)
8M	THED	Neutron Detector Well Fan-09
7F	THFK	Electric H_2 Recombiner Power Supply PNL-01
8RM	THED	Motor Operated Valve 1-HV-4075C

(a) Primary protection is provided by Gould Tronic TR5 fusible switch with 3.2A fuse.

Table 13.8.32-1a (Page 8 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION		SYSTEM POWERED
3.4	Device Location -	MCC 1EB4-2 Compartment numbers listed below.
	Primary and Backup Breakers -	Unless noted otherwise, both primary and backup breakers have identical trip ratings and are located in the same MCC compt. These breakers are General Electric type THED or THFK with thermal-magnetic trip elements.

MCC 1EB4-2 COMPT. NO.	G.E. BKR. TYPE	SYSTEM POWERED
1M	THED	JB-1S-1230G, Altern. Feed to Motor Operated Valve 1-8701B
8G	THED	Motor Operated Valve 1-8702A
8M	THED	Motor Operated Valve 1-8702B
4M	THED	Motor Operated Valve 1-8000B
4G	THED	Motor Operated Valve 1-HV-6075
3G	THED	Motor Operated Valve 1-HV-6077
3M	THED [(a)]	Motor Operated Valve 1-HV-6079
2G	THED	Motor Operated Valve 1-HV-5562
2M	THED [(a)]	Motor Operated Valve 1-HV-5563
5F	THED	Motor Operated Valve 1-8808B
5M	THED	Motor Operated Valve 1-8808D
6M	THED	Containment Ltg. XFMR-19(PNL SC2 & SC4)
7M	THED	Neutron Detector Well Fan-10
6F	THFK	Elect. H_2 Recombiner Power Supply PNL-02

(a) Primary protection is provided by Gould Tronic TR5 fusible switch with 3.2A fuse.

Table 13.8.32-1a (Page 9 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION		SYSTEM POWERED
4. 480VAC From Panelboards		
4.1 Pressurizer Heater Groups A, B, & D		
a. Primary Breakers	-	General Electric Type TJJ Thermal Magnetic breakers.
Breaker No. & Location	-	Ckt. Nos. 2 thru 4 of Panelboards 1EB2-1-2, 1EB3-1-2, 1EB4-1-1, 1EB4-1-2 and Ckt. Nos. 2 thru 5 of Panelboards 1EB2-1-1 and 1EB3-1-1.
b. Backup Breakers[(a)] -	-	General Electric Type THJS or TJH4S with longtime and insts. solid state trip devices with 400 Amp. sensor.
Breaker No. & Location	-	Ckt. No. 1 of Panelboards 1EB2-1-1, 1EB2-1-2, 1EB3-1-1, 1EB3-1-2, 1EB4-1-1 and 1EB4-1-2.
4.2 Pressurizer Heater group C		
a. Primary Breakers	-	General Electric Type THED breakers.
Breaker No. & Location	-	For both 1EB1-1-1 & 1EB1-1-2 are located at Ckt. Nos. 2 thru 4.
b. Backup Breakers	-	General Electric Type TJJ Thermal Magnetic breakers.
Breaker No. & Location	-	Ckt Nos. 2 thru 4 of Switchboards 1EB1-1-1 & 1EB1-1-2.

(a) When a branch circuit breaker is tripped or placed in the off position or there is an open in the heater circuit (e.g., an open heater element), then the breaker settings for the main (feeder) circuit breaker should be adjusted per drawing E1-2400-296. If a breaker was previously in the ‘off’ position and is then placed in the ‘on’ position, then the breaker settings for the main (feeder) circuit breaker should be adjusted per drawing E1-2400-296.

Table 13.8.32-1a (Page 10 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED

4.3 480VAC From Plant Support Power System Panelboards

Both primary and backup breakers have identical trip settings and are located in the same panel board. These breakers are Square D type FC, KH, and LH.

a) Panelboard 1B11-1-1

Device Location	Breaker Type	System Powered
Ckt 2	FC	Containment Elevator CP1-MEELRB-01
Ckt 4	KH	Welding Receptacles Distribution Panel 1B11-1-1-1
Ckt 6	LH	Containment Polar Crane CP1-MESCCP-01

b) Panelboard 1B11-1-2

Device Location	Breaker Type	System Powered
Ckt 2	FC	Fuel Transfer System Rx Side Cont. Pnl for TBX-FHSTTS-02
Ckt 14	FC	Containment Lighting Xfmr CP1-ELTRNT-14
Ckt 16	FC	Manipulator Crane 1-01 TBX-FHSCMC-01

Table 13.8.32-1a (Page 11 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
5. 120V Space Heater Circuits from 480V Switchgears	Containment Recirc. Fan and CRDM Vent Fan Motor Space Heaters

a. Primary Devices - N/A (Fuse)

b. Backup Breakers

BKR. LOCATION & NUMBER	WESTINGHOUSE BKR. TYPE
Swgr. 1EB1, Cubicle 3A, CP1-VAFNAV-01 Space Heater Bkr.	EB1010
Swgr. 1EB2, Cubicle 3A, CP1-VAFNAV-02 Space Heater Bkr.	EB1010
Swgr. 1EB3, Cubicle 9A, CP1-VAFNAV-03 Space Heater Bkr.	EB1010
Swgr. 1EB4, Cubicle 9A, CP1-VAFNAV-04 Space Heater Bkr.	EB1010
Swgr. 1EB3, Cubicle 8A, CP1-VAFNCB-01 Space Heater Bkr.	EB1010
Swgr. 1EB4, Cubicle 8A, CP1-VAFNCB-02 Space Heater Bkr.	EB1010

Table 13.8.32-1a (Page 12 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
6. 125V DC Control Power	Various

a. Primary Devices - N/A (Fuse)

b. Backup Breakers

PANELBOARD NO.	CKT.NO.	GENERAL ELECTRIC BREAKER TYPE
XED1-1	1,6	TED
XED2-1	3,6	TED
XD2-3	8	TED
1ED2-1	14,17	TED
1ED1-1	14	TED
1D2-3	10	TED
1ED3-1	5	TED
1ED1-2	7	TED
TBX-WPXILP-01	Main(LBK3)	FB(Westinghouse)

7. 120V AC Control Power from Isolation XFMR TXEC3 & TXEC4

a. Primary Devices - N/A (Fuse)

b. Backup Breakers - Square D Type QOB located in Miscellaneous Signal Control Cabinet.

1) Panel Board A, Ckt. Bkr. connected at TB4-13

2) Panel Board B, Ckt. Bkr. connected at TB6-7

8. 120V AC Power for Personnel and Emergency Airlocks

a. Primary Devices - N/A (Fuse)

b. Backup Breakers

PANELBOARD NO.	CKT.NO.	GENERAL ELECTRIC BREAKER TYPE
XEC2	34	TED
XEC1-2	2	TED

Table 13.8.32-1a (Page 13 of 13)
Unit 1 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED

9. 118V AC Control Power

   a. Primary Devices - N/A (Fuse)

   b. Backup Breakers

PANELBOARD NO.	CKT.NO.	GENERAL ELECTRIC BREAKER TYPE
1EC5	8	TED
1EC6	3	TED

10. Emergency Evacuation System Warning Lights Power

   a. Primary Devices - N/A (Fuse)

   b. Backup Breakers

PANELBOARD NO.	CKT.NO.	SQUARE D BREAKER TYPE
XEC3-3	9,10	FY

11. DRPI Data Cabinet Power Supplies

   a. Primary Breakers

PANELBOARD NO.	CKT.NO.	SQUARE D BREAKER TYPE
1C14	1,2	FA

   b. Backup Breakers

PANELBOARD NO.	CKT.NO.	SQUARE D BREAKER TYPE
1C14	Main Pnl. Bkrs.	FA

Table 13.8.32-1b (Page 1 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1. 6.9 KVAC from Switchgears	
a. Switchgear Bus 2A1	RCP #21
1) Primary Breaker 2PCPX1	
a) Relay 50M1-51	
b) Relay 86M	
2) Backup Breakers 2A1-1 or 2A1-2	
a) Relay 51M3	
b) Relay 51 for 2A1-1	
c) Relay 51 for 2A1-2	
d) Relay 86/2A1	
b. Switchgear Bus 2A2	RCP #22
1) Primary Breaker 2PCPX2	
a) Relay 50M1-51	
b) Relay 86M	
2) Backup Breakers 2A2-1 or 2A2-2	
a) Relay 51M3	
b) Relay 51 for 2A2-1	
c) Relay 51 for 2A2-2	
d) Relay 86/2A2	

Table 13.8.32-1b (Page 2 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
c. Switchgear Bus 2A3	RCP #23
1) Primary Breaker 2PCPX3	
a) Relay 50M1-51	
b) Relay 86M	
2) Backup Breakers 2A3-1 or 2A3-2	
a) Relay 51M3	
b) Relay 51 for 2A3-1	
c) Relay 51 for 2A3-2	
d) Relay 86/2A3	
d. Switchgear Bus 2A4	RCP #24
1) Primary Breaker 2PCPX4	
a) Relay 50M1-51	
b) Relay 86M	
2) Backup Breaker 2A4-1 or 2A4-2	
a) Relay 51M3	
b) Relay 51 for 2A4-1	
c) Relay 51 for 2A4-2	
d) Relay 86/2A4	

Table 13.8.32-1b (Page 3 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2. 480 VAC from Switchgears	
2.1 480V Switchgear 2EB1	
1. Compartment 3B	Containment Recirc Fan CP2-VAFNAV-01
a) Primary Breaker 2FNAV1	
1) Relay: Amptector Trip Unit of Breaker 2FNAV1	
b) Backup Breakers 2EB1-1 and BT-2EB13	
1) Long Time and Instantaneous Relay $\frac{50-51}{2FNAV1}$	
2) Time Delay Relay $\frac{62-1}{2FNAV1}$	
2.2 480V Switchgear 2EB2	
1. Compartment 3B	Containment Recirc Fan CP2-VAFNAV-02
a) Primary Breaker 2FNAV2	
1) Relay: Amptector Trip Unit of Breaker 2FNAV2	
b) Backup Breakers 2EB2-1 and BT-2EB24	
1) Long Time and Instantaneous Relay $\frac{50-51}{2FNAV2}$	
2) Time Delay Relay $\frac{62-1}{2FNAV2}$	
2.3 480V Switchgear 2EB3	
1. Compartment 8B	CRDM Vent Fan CP2-VAFNCB-01
a) Primary Breaker 2FNCB1	
1) Relay: Amptector Trip Unit of Breaker 2FNCB1	
b) Backup Breakers 1EB3-1 and BT-1EB13	
1) Long Time and Instantaneous Relay $\frac{50-51}{2FNCB1}$	
2) Time Delay Relay $\frac{62-1}{2FNCB1}$	
2. Compartment 9B	Containment Recirc Fan CP2-VAFNAV-03
a) Primary Breaker 2FNAV3	
1) Relay: Amptector Trip Unit of Breaker 2FNAV3	
b) Backup Breakers 2EB3-1 and BT-2EB13	
1) Long Time and Instantaneous Relay $\frac{50-51}{2FNAV3}$	
2) Time Delay Relay $\frac{62-1}{2FNAV3}$	

Table 13.8.32-1b (Page 4 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2.4 480V Switchgear 2EB4	
1. Compartment 8B	CRDM Vent Fan CP2-VAFNCB-02
a) Primary Breaker 2FNCB2	
1) Relay: Amptector Trip Unit of Breaker 2FNCB2	
b) Backup Breakers 2EB4-1 and BT-2EB24	
1) Long Time and Instantaneous Relay $\frac{50-51}{2FNCB2}$	
2) Time Delay Relay $\frac{62-1}{2FNCB2}$	
2. Compartment 9B	Containment Recirc Fan CP2-VAFNAV-04
a) Primary Breaker 2FNAV4	
1) Relay: Amptector Trip Unit of Breaker 2FNAV4	
b) Backup Breakers 2EB4-1 and BT-2EB24	
1) Long Time and Instantaneous Relay $\frac{50-51}{2FNAV4}$	
2) Time Delay Relay $\frac{62-1}{2FNAV4}$	

Table 13.8.32-1b (Page 5 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED

3. 480VAC from Motor Control Centers

3.1 Device Location - MCC 2EB1-2 Compartment Numbers listed below.
Primary and Backup Breakers - Both primary and backup breakers have identical trip ratings and are in the same MCC Compt. These breakers are General Electric type THED with thermal-magnetic trip elements.

MCC 2EB1-2 COMPT. NO.	G.E. BKR. TYPE	SYSTEM POWERED
4G	THED	Motor Operated Valve 2-TV-4691
4M	THED	Motor Operated Valve 2-TV-4693
3F	THED	Containment Drain Tank Pump-03
9H	THED	Reactor Cavity Sump Pump-01
9M	THED	Reactor Cavity Sump Pump-02
7H	THED	Containment Sump #1 Pump-01
7M	THED	Containment Sump #1 Pump-02
6H	THED	RCP #21 Motor Space Heater-01
6M	THED	RCP #23 Motor Space Heater-03
8B	THED	Incore Detector Drive "A"
8D	THED	Incore Detector Drive "B"
7B	THED	Incore Detector Drive "F"
3B	THED	Stud Tensioner Hoist Outlet-01
7D	THED	Hydraulic Deck Lift-01
4B	THED	Reactor Coolant Pump Motor Hoist Receptacle-42
8H	THED	RC Pipe Penetration Cooling Unit-01
8M	THED	RC Pipe Penetration Cooling Unit-02
5H	THED	RCP #21 Oil Lift Pump-01
5M	THED	RCP #23 Oil Lift Pump-03
10B	THED	Preaccess Filter Train Package Receptacle-17
10F	THED	S.G. Wet Layup Circ. Pump 01 (CP2-CFAPRP-01)
12M	THED	S.G. Wet Layup Circ. Pump 03 (CP2-CFAPRP-03)
12H	THED	Containment Ltg. XFMR-28 (PNL 2C11 & 2C12)
12B	THED	Personnel Air Lock Hydraulic Unit #2 (CP2-BSAPPA-02M)
2M	THED	RC Drain Tank Pump No. 1
2F	THED	Containment Ltg. XFMR-16 (PNL 2C7 & 2C9)
1M	THED	Containment Ltg. XFMR-12 (PNL 2LPC1 & 2LPC5)
3M	THED	Preaccess Fan No. 11

Table 13.8.32-1b (Page 6 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
3.2 Device Location	- MCC 2EB2-2 Compartment Numbers listed below.
Primary and Backup Breakers	- Both primary and backup breakers have identical trip ratings and are located in the same MCC compt. These breakers are General Electric type THED with thermal-magnetic trip elements.

MCC 2EB2-2 COMPT. NO.	G.E. BKR. TYPE	SYSTEM POWERED
4G	THED	Motor Operated Valve 2-TV-4692
4M	THED	Motor Operated Valve 2-TV-4694
3F	THED	Containment Drain Tank Pump-04
7H	THED	Containment Sump No. 2 Pump-03
7M	THED	Containment Sump No. 2 Pump-04
6H	THED	RCP #22 Motor Space Heater-02
6M	THED	RCP #24 Motor Space Heater-04
5B	THED	Incore Detector Drive "C"
2B	THED	Incore Detector Drive "D"
7B	THED	Incore Detector Drive "E"
5D	THED	Containment Fuel Storage Crane-01
3B	THED	Stud Tensioner Hoist Outlet-02
10B	THED	RCC Change Fixture Hoist Drive-01
10F	THED	Refueling Cavity Skimmer Pump-01
12B	THED	Power Receptacles (Cont. E1. 841')
1M	THED	S.G. Wet Layup Circ. Pump 02 (CP2-CFAPRP-02)
12M	THED	S.G. Wet Layup Circ. Pump 04 (CP2-CFAPRP-04)
8H	THED	RC Pipe Penetration Fan-03
8M	THED	RC Pipe Penetration Fan-04
5H	THED	RCP #22 Oil Lift Pump-02
5M	THED	RCP #24 Oil Lift Pump-04
12H	THED	Preaccess Filter Train Package Receptacles - 18
6D	THED	Containment Auxiliary Upper Crane-01 [(a)]
2F	THED	Containment Ltg. XFMR-13 (PNL 2LPC2)
2D	THED	Containment Access Rotating Platform-01
2M	THED	Reactor Coolant Drain Tank Pump-02
9F	THED	Containment Ltg. XFMR-17 (PNL 2C8 & 2C10)
9M	THED	Containment Ltg. XFMR-15 (PNL 2LPC4 & 2LPC6)
3M	THED	Preaccess Fan-12

(a) Upon implementation and acceptance by Operations of FDA-2002-001062-05; the Systems Powered is changed from “Containment Auxiliary Upper Crane –01” to “Containment Building Welding Receptacle El. 905’-9”.”

Table 13.8.32-1b (Page 7 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED

3.3 Device Location - MCC 2EB3-2 Compartment numbers listed below.
Primary and Backup - Unless noted otherwise, both primary and backup breakers have identical trip ratings and are located in the same MCC compt. These breakers are General Electric type THED or THFK with thermal-magnetic trip elements.

MCC 2EB3-2 COMPT. NO.	G.E. BKR. TYPE	SYSTEM POWERED
8RF	THED	Altern. Feed to Motor Operated Valve 2-8702A
1G	THED	Motor Operated Valve 2-8112
9G	THED	Motor Operated Valve 2-8701A
9M	THED	Motor Operated Valve 2-8701B
5M	THED	Motor Operated Valve 2-8000A
5G	THED	Motor Operated Valve 2-HV-6074
4G	THED	Motor Operated Valve 2-HV-6076
4M	THED [(a)]	Motor Operated Valve 2-HV-6078
2G	THED	Motor Operated Valve 2-HV-4696
2M	THED	Motor Operated Valve 2-HV-4701
3G	THED	Motor Operated Valve 2-HV-5541
3M	THED	Motor Operated Valve 2-HV-5543
1M	THED	Motor Operated Valve 2-HV-6083
6F	THED	Motor Operated Valve 2-8808A
6M	THED	Motor Operated Valve 2-8808C
7M	THED	Containment Ltg. XFMR-18 (PNL 2SC1 & 2SC3)
8M	THED	Neutron Detector Well Fan-09
7F	THFK	Electric H_2 Recombiner Power Supply PNL-01
8RM	THED	Motor Operated Valve 2-HV-4075C

(a) Primary protection is provided by Gould Tronic TR5 fusible switch with 3.2A fuse.

Table 13.8.32-1b (Page 8 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
3.4 Device Location -	MCC 2EB4-2 Compartment numbers listed below.
Primary and Backup -	Unless noted otherwise, both primary and backup breakers have identical trip ratings and are located in the same MCC compt. These breakers are General Electric type THED or THFK with thermal-magnetic trip elements.

MCC 2EB4-2 COMPT. NO.	G.E. BKR. TYPE	SYSTEM POWERED
1M	THED	Altern. Feed to Motor Operated Valve 2-8701B
8G	THED	Motor Operated Valve 2-8702A
8M	THED	Motor Operated Valve 2-8702B
4M	THED	Motor Operated Valve 2-8000B
4G	THED	Motor Operated Valve 2-HV-6075
3G	THED	Motor Operated Valve 2-HV-6077
3M	THED [(a)]	Motor Operated Valve 2-HV-6079
2G	THED [(a)]	Motor Operated Valve 2-HV-5562
2M	THED [(a)]	Motor Operated Valve 2-HV-5563
5F	THED	Motor Operated Valve 2-8808B
5M	THED	Motor Operated Valve 2-8808D
6M	THED	Containment Ltg. XFMR-19 (PNL 2SC2 & 2SC4)
7M	THED	Neutron Detector Well Fan-10
6F	THFK	Elect. H_2 Recombiner Power Supply PNL-02

(a) Primary protection is provided by Gould Tronic TR5 fusible switch with 3.2A fuse.

Table 13.8.32-1b (Page 9 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION		SYSTEM POWERED
4. 480VAC From Panelboards		
4.1 Pressurizer Heater Groups A, B, & D		
a. Primary Breakers	-	General Electric Type TJJ Thermal Magnetic breakers.
Breaker No. & Location	-	Ckt. Nos. 2 thru 4 of Panelboards 2EB2-1-2, 2EB3-1-2, 2EB4-1-1, 2EB4-1-2 and Ckt. Nos. 2 thru 5 of Panelboards 2EB2-1-1 and 2EB3-1-1.
b. Backup Breakers[(a)]	-	General Electric Type THJS or TJH4S with longtime and insts. solid state trip devices with 400 Amp. sensor.
Breaker No. & Location	-	Ckt. No. 1 of Panelboards 2EB2-1-1, 2EB2-1-2, 2EB3-1-1, 2EB3-1-2, 2EB4-1-1 and 2EB4-1-2.
4.2 Pressurizer Heater group C		
a. Primary Breakers	-	General Electric Type THED breakers.
Breaker No. & Location	-	For both 2EB1-1-1 & 2EB1-1-2 are located at Ckt. Nos. 2 thru 4.
b. Backup Breakers	-	General Electric Type TJJ Thermal Magnetic breakers.
Breaker No. & Location	-	Ckt Nos. 2 thru 4 of Switchboards 2EB1-1-1 & 2EB1-1-2.

(a) When a branch circuit breaker is tripped or placed in the off position or there is an open in the heater circuit (e.g., an open heater element), then the breaker settings for the main (feeder) circuit breaker should be adjusted per drawing E2-2400-296. If a breaker was previously in the ‘off’ position and is then placed in the ‘on’ position, then the breaker settings for the main (feeder) circuit breaker should be adjusted per drawing E2-2400-296.

Table 13.8.32-1b (Page 10 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED

4.3 480VAC From Plant Support Power System Panelboards

Both primary and backup breakers have identical trip settings and are located in the same panelboard (with the exception of Ckt 1 / Bkr-1 located in Panelboard 2B10-1-2 and Ckt 1 / Bkr-2 located in Panelboard 2B10-1-2a). These breakers are Square D type FH, KH, FA, and LH.

a) Panelboard 2B10-1-2

Device Location	Breaker Type	System Powered
Ckt 2	FH	Containment Elevator CP2-MEELRB-01
Ckt 4	KH	Containment Welding Receptacles
Ckt 6	LH	Containment Polar Crane CP2-MESCCP-01
Ckt 1 / Bkr-1	LH	Containment Jib Crane CP2-MEMECA-16 Disconnect Switches CP2-ECDSNC-15&16

b) Panelboard 2B10-1-1-1

Device Location	Breaker Type	System Powered
Ckt 4 (b)	FH	Personnel Airlock Hydraulic Unit #2 (CP2-BSAPPA-02M)
Ckt 6	FH	Fuel Transfer System Rx Side Cont. Pnl for TCX-FHSTTS-02
Ckt 10	FH	Containment Lighting Xfmr CP2-ELTRNT-14
Ckt 8	FH	Manipulator Crane 1-01 TXC-FHSCMC-01

c) Panelboard 2B10-1-2a

Device Location	Breaker Type	System Powered
Ckt 1/Bkr-2	FA	Containment Jib Crane CP2-MEMECA-16 Disconnect Switches CP2-ECDSNC-15 &16

(b) Breakers become electrical penetration overcurrent protection devices only when transfer switch CP2-BSTSNB-01 is aligned to plant support power panel 2B10-1-1-1/04/BKR-1 and 2. Transfer switch CP2-BSTSNB-01 is normally aligned to MCC 2EB1-2/12B/BKR-1 and 2.

Table 13.8.32-1b (Page 11 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
5. 120V Space Heater Circuits from 480V Switchgears	Containment Recirc. Fan and CRDM Vent Fan Motor Space Heaters

a. Primary Devices - N/A (Fuse)

b. Backup Breakers

BKR. LOCATION & NUMBER	WESTINGHOUSE BKR. TYPE
Swgr. 2EB1, Cubicle 3A, CP2-VAFNAV-01 Space Heater Bkr.	EB1010
Swgr. 2EB2, Cubicle 3A, CP2-VAFNAV-02 Space Heater Bkr.	EB1010
Swgr. 2EB3, Cubicle 9A, CP2-VAFNAV-03 Space Heater Bkr.	EB1010
Swgr. 2EB4, Cubicle 9A, CP2-VAFNAV-04 Space Heater Bkr.	EB1010
Swgr. 2EB3, Cubicle 8A, CP2-VAFNCB-01 Space Heater Bkr.	EB1010
Swgr. 2EB4, Cubicle 8A, CP2-VAFNCB-02 Space Heater Bkr.	EB1010

Table 13.8.32-1b (Page 12 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
6. 125V DC Control Power	Various

a. Primary Devices - N/A (Fuse)

b. Backup Breakers

PANELBOARD NO.	CKT. NO.	GENERAL ELECTRIC BREAKER TYPE
XED1-1	6 [c]	TED
XED2-1	6 [c]	TED
2ED2-1	11,17	TED
2ED1-1	11	TED
2D2-3	6,10,11	TED [a]
2D2-2	9	TED [a]
2ED2-2	12	TED [a]
2ED3-1	5	TED
2ED1-2	7,8	TED [a]
TBX-WPXILP-01	Main(LBK3) [c]	FB(Westinghouse)

7. 120V AC Control Power from Isolation XFMR TXEC3 & TXEC4

a. Primary Devices - N/A (Fuse)

b. Backup Breakers - Square D Type QOB located in Miscellaneous Signal Control Cabinet.

1) Panel Board A, Ckt. Bkr. connected at TB3-5

2) Panel Board B, Ckt. Bkr. connected at TB5-1

(a) Upon implementation and acceptance by Operations of FDA-2002-002756-01; breakers 2D2-3/11, 2D2-2/9, 2ED2-2/12, and 2ED1-2/8 are no longer required meet the requirements of TRM 13.8.32.

(c) These circuits provide backup protection to both Units 1 and 2. Testing of these breakers is controlled by Unit 1 surveillance program.

Table 13.8.32-1b (Page 13 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED

8. 120 AC Power for Personnel and Emergency Airlocks

   a. Primary Devices - N/A (Fuse)

   b. Backup Breakers

PANELBOARD NO.	CKT. NO.	GENERAL ELECTRIC BREAKER TYPE
XEC1	12	TED
XEC2-2	3	TED

9. 118V AC Control Power

   a. Primary Devices - N/A (Fuse)

   b. Backup Breakers

PANELBOARD NO.	CKT. NO.	GENERAL ELECTRIC BREAKER TYPE
2C2	22	TED [(a)]
2PC1	10	TED [(a)]
2PC4	10	TED [(a)]
2EC1	7	TED [(a)]
2EC2	4,7	TED[(a)]
2EC5	8	TED
2EC6	3,8	TED [(a)]

(a) Upon completion and acceptance by Operations of FDA-2002-002756-01; breakers 2C2/22, 2PC1/10, 2PC4/10, 2EC1/7, 2EC2/4, 2EC2/7, and 2EC6/8 are no longer required to meet the requirements of TRM 13.8.32.

Table 13.8.32-1b (Page 14 of 14)
Unit 2 Containment Penetration Conductor
Overcurrent Protective Devices

DEVICE NUMBER AND LOCATION	SYSTEM POWERED

10. Emergency Evacuation System Warning Lights Power

    a. Primary Devices - N/A (Fuse)

    b. Backup Breakers

PANELBOARD NO.	CKT. NO.	SQUARE D BREAKER TYPE
XEC4-3	9,10	FY

11. DRPI Data Cabinet Power Supplies

    a. Primary Breakers

PANELBOARD NO.	CKT. NO.	SQUARE D BREAKER TYPE
2C14	1,2	FA

    b. Backup Breakers

PANELBOARD NO.	CKT. NO.	SQUARE D BREAKER TYPE
2C14	Main Pnl. Bkrs.	FA

13.9 REFUELING OPERATIONS

TR 13.9.31 Decay Time

TR LCO 13.9.31 The reactor shall be subcritical for at least 100 hours.

APPLICABILITY: During movement of irradiated fuel in the reactor vessel.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor subcritical for less than 100 hours.	A.1 Suspend all operations involving movement of irradiated fuel in the reactor vessel.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.9.31.1	Determine the reactor has been subcritical for at least 100 hours by verification of the date and time of subcriticality.	Prior to movement of irradiated fuel in the reactor vessel.

13.9 REFUELING OPERATIONS

TR 13.9.32 Refueling Operations / Communications

TR LCO 13.9.32 Direct communications shall be maintained between the control room and personnel at the refueling station.

APPLICABILITY: During CORE ALTERATIONS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. No direct communications between the control room and personnel at the refueling station.	A.1 Suspend all CORE ALTERATIONS.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.9.32.1	Verify direct communications between the control room and personnel at the refueling station.	Once within 1 hour prior to the start of CORE ALTERATIONS <u>AND</u> 12 hours

13.9 REFUELING OPERATIONS

TR 13.9.33 Refueling Machine

TR LCO 13.9.33 The refueling machine main hoist and auxiliary monorail hoist shall be used for movement of drive rods or fuel assemblies and shall be OPERABLE with:

a. The refueling machine main hoist used for movement of fuel assemblies having:

1. A minimum capacity of 2850 pounds, and

2. An overload cutoff limit less than or equal to 2800 pounds.

b. The auxiliary monorail hoist used for latching, unlatching and movement of control rod drive shafts having:

1. A minimum capacity of 610 pounds, and

2. A load indicator which shall be used to prevent lifting loads in excess of 600 pounds.

APPLICABILITY: During movement of fuel assemblies and/or latching, unlatching or movement of control rod drive shafts within the reactor vessel

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements for refueling machine main hoist and/or auxiliary monorail hoist OPERABILITY not satisfied.	A.1 Suspend use of any inoperable refueling machine main hoist and/ or auxiliary monorail hoist from operations involving the movement of fuel assemblies and/or latching, unlatching or movement of control rod drive shafts within the reactor vessel.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.9.33.1	The refueling machine main hoist used for movement of fuel assemblies within the reactor vessel shall be demonstrated OPERABLE by performing a load test of at least 2850 pounds and demonstrating an automatic load cutoff when the main hoist load exceeds 2800 pounds.	Once within 100 hours prior to the start of such operations
TRS 13.9.33.2	The auxiliary monorail hoist and associated load indicator used for latching, unlatching or movement of control rod drive shafts within the reactor vessel shall be demonstrated OPERABLE by performing a load test of at least 610 pounds.	Once within 100 hours prior to the start of such operations

13.9 REFUELING OPERATIONS

TR 13.9.34 Refueling - Crane Travel - Spent Fuel Storage Areas

TR LCO 13.9.34 Loads in excess of 2150 pounds shall be prohibited from travel over fuel assemblies in a storage pool.

APPLICABILITY: With fuel assemblies in the storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Technical Requirement not met.	A.1. Place the crane load in a safe condition.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.9.34.1	-- - NOTE - Only required to be performed when the hoist is being used to move loads over fuel assemblies in a spent fuel storage pool. -- Each hoist load indicator shall be demonstrated OPERABLE by performing a load test of at least 2200 pounds.	7 days

13.9 REFUELING OPERATIONS

TR 13.9.35 Water Level, Reactor Vessel, Control Rods

TR LCO 13.9.35 At least 23 feet of water shall be maintained over the top of the irradiated fuel assemblies within the reactor vessel.

APPLICABILITY: During movement of control rods within the reactor vessel while in MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Technical Requirement not met.	A.1 Suspend all operations involving movement of control rods within the reactor vessel.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.9.35.1	The water level shall be determined to be at least its minimum required depth.	24 hours <u>AND</u> Once within 2 hours prior to the movement of control rods in MODE 6

13.9 REFUELING OPERATIONS

TR 13.9.36 Fuel Storage Area Water Level

TR LCO 13.9.36 The fuel storage area water level shall be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: Whenever irradiated fuel assemblies are in the storage racks.

- NOTE -

While This LCO is not met, do not commence crane operations with loads over irradiated fuel in the storage racks.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel storage area water level < 23 feet above irradiated fuel assemblies seated in the storage racks.	A.1 Suspend crane operations with loads in the affected fuel storage areas and restore the water level to within its limit.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.9.36.1	Verify the fuel storage area water level ≥ 23 ft above the irradiated fuel assemblies seated in the storage racks.	7 days

13.10 EXPLOSIVE GAS AND STORAGE TANK RADIOACTIVITY MONITORING PROGRAM

TR 13.10.31 Explosive Gas Monitoring Instrumentation

TR LCO 13.10.31 Pursuant to Technical Specification 5.5.12a, the explosive gas monitoring instrumentation channels shown in Table 13.10.31-1 shall be OPERABLE with their Alarm/Trip Setpoints set to ensure that the limits specified in TR 13.10.34 are not exceeded.

APPLICABILITY: During Waste Gas Holdup System operation on the inservice recombiner.

ACTIONS

- NOTE -

Separate Condition entry is allowed for each recombiner.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. An explosive gas monitoring instrumentation channel Alarm/Trip Setpoint less conservative than required.	A.1 Declare channel inoperable.	Immediately
B. Any required channel inoperable.	B.1 Restore the inoperable channel to OPERABLE status.	30 days
C. No inlet oxygen monitor channel OPERABLE on the inservice recombiner.	C.1 Verify the associated inlet hydrogen monitor(s) OPERABLE.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. No outlet oxygen monitor channel OPERABLE on the inservice recombiner.	D.1 Suspend operation of the Waste Gas Holdup System.	Immediately
	OR	
	D.2 Take and analyze grab samples while maintaining oxygen < 1% by volume.	Once per 24 hours
E. Less than the required hydrogen monitor Channels OPERABLE on the inservice recombiner. OR No inlet oxygen monitor channel and no outlet oxygen monitor channel OPERABLE on the inservice recombiner. OR No inlet oxygen monitor channel and no inlet hydrogen monitor channel OPERABLE on the inservice recombiner.	E.1 Suspend oxygen supply to the affected recombiner(s).	Immediately
	AND	
	E.2.1 Suspend addition of waste gas to the system.	Immediately
	OR	
	E.2.2 Take and analyze grab samples while maintaining oxygen < 1% by volume.	Once per 4 hours during degassing OR Once per 24 hours during other operations

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.10.31.1	Perform a CHANNEL CHECK of each explosive gas monitoring instrumentation channel shown in Table 13.10.31-1.	Once per 24 hours during Waste Gas Holdup System operation <u>AND</u> Once per 24 hours prior to Waste Gas Holdup System operation.
TRS 13.10.31.2	Perform a CHANNEL OPERATIONAL TEST of each explosive gas monitoring instrumentation channel shown in Table 13.10.31-1.	31 days
TRS 13.10.31.3	Perform a CHANNEL CALIBRATION of each explosive gas monitoring instrumentation channel shown in Table 13.10.31-1. This shall include the use of standard gas samples in accordance with the manufacturer's recommendations.	92 days

Table 13.10.31-11
Explosive Gas Monitoring Instrumentation *

INSTRUMENT	REQUIRED CHANNELS
1. Waste Gas Holdup System Explosive Gas Monitoring System	
a. Hydrogen Monitors	1 per recombiner
b. Oxygen Monitors	2 per recombiner

* One hydrogen and two oxygen monitors are required to be OPERABLE for the operating recombiner during Waste Gas HOLDUP System operation

13.10 EXPLOSIVE GAS AND STORAGE TANK RADIOACTIVITY MONITORING PROGRAM

TR 13.10.32 Gas Storage Tanks

TR LCO 13.10.32 Pursuant to TS 5.5.12b, the quantity of radioactivity contained in each gas storage tank shall be ≤ 200,000 Curies of noble gases (considered as Xe-133 equivalent).

APPLICABILITY: At all times.

ACTIONS

- NOTE -

Separate condition entry allowed for each gas storage tank.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Radioactivity in one or more storage tank(s) not within limit.	A.1 Suspend all additions of radioactive material to the tank(s).	Immediately
	AND	
	A.2 Reduce radioactivity in tank(s) to within limit.	48 hours
	AND	
	A.3 -- - NOTE - Required Action A.3 must be completed whenever Condition A is entered. --	
	Describe events leading to exceeding limits in Radioactive Effluent Release Report.	Per TS 5.6.3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.10.32.1	-- - NOTE - Only required to be performed when radioactive materials are being added to the tank. -- Determine the quantity of radioactive material in each gas storage tank to verify within limit.	Once within 92 days after the addition of radioactive material being added to the tank, but not more often than 92 days

13.10 EXPLOSIVE GAS AND STORAGE TANK RADIOACTIVITY MONITORING PROGRAM

TR 13.10.33 Liquid Holdup Tanks

TR LCO 13.10.33 Pursuant to TS 5.5.12c, the quantity of radioactive material in each outdoor unprotected tank shall be limited to ≤10 Curies, excluding tritium and dissolved or entrained noble gases.

APPLICABILITY: At all times.

ACTIONS

- NOTE -
Separate Condition entry allowed for each tank.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Quantity of radioactive material in one or more tanks exceeds limits.	A.1 Suspend all additions of radioactive material to the tank(s).	Immediately.
	AND	
	A.2 Reduce quantity of radioactive material in tank(s) to within limits.	48 hours
	AND	
	A.3 --- - NOTE - Required Action A.3 must be completed whenever Condition A is entered. ---	
	Describe events leading to exceeding limits in Radioactive Effluent Release Report.	Per TS 5.6.3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.10.33.1	-- - NOTE - Only required to be performed when radioactive materials are being added to the tank. -- Analyze a representative sample of each tank's contents to verify within limits.	7 days

13.10 EXPLOSIVE GAS AND STORAGE TANK RADIOACTIVITY MONITORING PROGRAM

TR 13.10.34 Explosive Gas Mixture

TR LCO 13.10.34 Pursuant to TS 5.5.12a, the concentration of oxygen in the Waste Gas Holdup system shall be ≤ 3% by volume whenever the hydrogen concentration is > 4% by volume.

APPLICABILITY: At all times.

ACTIONS

- NOTE -

Only applicable when hydrogen concentration in the Waste Gas Holdup system is > 4% by volume.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Oxygen concentration in Waste Gas Holdup system > 3% by volume and ≤ 4% by volume.	A.1 Reduce oxygen concentration to within limits.	48 hours
B. Oxygen concentration in Waste Gas Holdup System > 4% by volume.	B.1 Suspend all additions of waste gases to the system.	Immediately
	AND	
	B.2 Reduce oxygen concentration to ≤ 4% by volume.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TRS 13.10.34.1	Monitor the hydrogen and oxygen in the Waste Gas Holdup Systems as specified by TR 13.10.31.	As specified in TR 13.10.31

15.0 ADMINISTRATIVE CONTROLS

15.5 Programs and Manuals

TR 15.5.17 TRM - Administrative Control Process

a. Introduction

CPSES has relocated certain information from the Technical Specifications to a separate controlled document based on the NUMARC Technical Specification Improvement Program, the Westinghouse Owners Group MERITS Program, and the Commission's Interim Policy Statement for improvement of Technical Specifications for nuclear power plants (52 FR 3788 of February 6, 1987). This information is now contained in a separate document to be called the CPSES Technical Requirements Manual (TRM). The following is a description of the administrative program for control, distribution, updating, and amending the information contained in the TRM. The Explosive Gas and Storage Tank Radioactivity Monitoring Program, as required by TS 5.5.12, is contained in Section 13.10 of the TRM.

b. Document Control

The TRM is considered a licensing basis document and as such, overall control of the document is addressed by the site-wide procedures for licensing document control.

c. Document Distribution

The TRM is considered a controlled document and distribution is controlled by site wide procedures for licensing basis document control.

(continued)

d. Changes / Deletions to the TRM

Changes to the TRM are controlled by the procedure on licensing document change control. This procedure addresses the administrative requirements necessary to change/amend CPSES licensing documents (e.g., Fire Protection Report, Offsite Dose Calculation Manual). For changes to the TRM, the procedure requires initiation of a Licensing Document Change Request (LDCR). The LDCR is the mechanism whereby changes are tracked to ensure that appropriate reviews, approvals, and signatures are obtained. TRM changes are evaluated per 10CFR50.59. TRM changes require a review by SORC and the approval of the Plant Manager*. Changes to the TRM must comply with the requirements of Technical Specification 5.5.17 of the CPSES Units 1 and 2 Technical Specifications.

e. Plant Changes That May Affect the TRM

Changes made at CPSES have the potential to affect (or be affected by) the TRM. These include items such as design modifications, procedure changes, other licensing document changes, etc. When TRM changes are required, the changes should be initiated and approved consistent with the plant activity (e.g., modification, procedure change etc.).

f. Distribution of TRM Changes / Deletions

Changes to the TRM will be issued on a replacement page basis to controlled document holders promptly following approval of the change.

g. Report of TRM Changes / Deletions to the NRC

Changes to the TRM will be reported to the NRC on the same frequency as the FSAR.

Proposed TRM changes that are determined to require prior NRC approval (as defined by 10CFR50.59) will either not be made or will be submitted to the NRC for prior review and approval.

TR 15.5.31 Snubber Augmented Inservice Inspection Program

a. Inspection Types

As used in this specification, type of snubber shall mean snubbers of the same design and manufacturer, irrespective of capacity.

* Duties may be performed by the Vice President of Nuclear Operations if that organizational position is assigned.

(continued)

b. <u>Visual Inspections</u>

Snubbers are categorized as inaccessible or accessible during reactor operation. Each of these groups (inaccessible and accessible) may be inspected independently. The first inservice visual inspection of each type of snubber shall be performed after 2 months but within 10 months of commencing POWER OPERATION and shall include all snubbers. If all snubbers of each type on any system are found OPERABLE during the first inservice visual inspection, the second inservice visual inspection on that type shall be performed at the first refueling outage. Otherwise subsequent visual inspections of a given system shall be performed in accordance with the following schedule:

No. of Inoperable Snubbers of Each Type on any System per Inspection Period*	Subsequent Visual Inspection Period**
0,1	12 months ± 25%
2	6 months ± 25%
3,4	124 days ± 25%
5,6,7	62 days ± 25%
8 or more	31 days ± 25%

* If one or more snubbers of each type on any system are found inoperable during the first inservice visual inspection, the second inservice visual inspection on that type shall be performed no later than the first refueling outage or the subsequent visual inspection period, whichever comes first.

** The inspection interval for each type of snubber shall not be lengthened more than one step at a time unless a generic problem has been identified and corrected; in that event the inspection interval may be lengthened one step the first time and two steps thereafter if no inoperable snubbers of that type are found on any system.

Visual inspection intervals following the second refueling outage shall be determined based upon the criteria provided in the Table 15.5.31-1.

(continued)

c. Visual Inspection Acceptance Criteria

Visual inspections shall verify that: (1) there are no visible indications of damage or impaired OPERABILITY, (2) attachments to the foundation or supporting structure are secure, and (3) fasteners for attachment of the snubber to the component and to the snubber anchorage are secure. Snubbers which appear inoperable as a result of visual inspections may be determined OPERABLE for the purpose of establishing the next visual inspection interval, provided that: (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers irrespective of type that may be generically susceptible; or (2) the affected snubber is functionally tested in the as-found condition and determined OPERABLE per 15.5.31f, the Functional Test Acceptance Criteria. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as inoperable snubbers.

d. Transient Event Inspection

An inspection shall be performed of all snubbers attached to sections of systems that have experienced unexpected, potentially damaging transients as determined from a review of operational data. A visual inspection of those systems shall be performed within 6 months following such an event. In addition to satisfying the visual inspection acceptance criteria, freedom-of-motion of mechanical snubbers shall be verified using at least one of the following: (1) manually induced snubber movement; or (2) evaluation of in-place snubber piston setting; or (3) stroking the mechanical snubber through its full range of travel.

e. Functional Tests

During the first refueling shutdown and at least once per 18 months thereafter during shutdown, a representative sample of snubbers of each type shall be tested using one of the following sample plans. The sample plan for each type shall be selected prior to the test period and cannot be changed during the test period. The NRC Regional Administrator shall be notified in writing of the sample plan selected for each snubber type prior to the test period or the sample plan used in the prior test period shall be implemented:

1. At least 10% of the total of each type of snubber shall be functionally tested either in-place or in a bench test. For each snubber of a type that does not meet the functional test acceptance criteria of Test/Inspection TR3.1f, an additional 10% of that type of snubber shall be functionally tested until no more failures are found or until all snubbers of that type have been functionally tested; or

(continued)

2. A representative sample of each type of snubber shall be functionally tested in accordance with Figure 15.5.31-1. "C" is the total number of snubbers of a type found not meeting the acceptance requirements of 15.5.31f. The cumulative number of snubbers of a type tested is denoted by "N". At the end of each day's testing, the new values of "N" and "C" (previous day's total plus current day's increments) shall be plotted on Figure 15.5.31-1. If at any time the point plotted falls in the "Accept" region, testing of snubbers of that type may be terminated. When the point plotted lies in the "Continue Testing" region, additional snubbers of that type shall be tested until the point falls in the "Accept" region, or all the snubbers of that type have been tested.

f. Functional Test Acceptance Criteria

The snubber functional test shall verify that:

1. Activation (restraining action) is achieved within the specified range in both tension and compression;

2. Snubber bleed, or release rate where required, is present in both tension and compression, within the specified range;

3. For mechanical snubbers, the force required to initiate or maintain motion of the snubber is within the specified range in both directions of travel.

Testing methods may be used to measure parameters indirectly or parameters other than those specified if those results can be correlated to the specified parameters through established methods.

g. Functional Test Failure Analysis

An engineering evaluation shall be made of each failure to meet the functional test acceptance criteria to determine the cause of the failure. The results of this evaluation shall be used, if applicable, in selecting snubbers to be tested in an effort to determine the OPERABILITY of other snubbers irrespective of type which may be subject to the same failure mode.

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

(continued)

If any snubber selected for functional testing either fails to lock up or fails to move, i.e., frozen in-place, the cause will be evaluated and, if caused by manufacturer or design deficiency, all snubbers of the same type subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated in 15.5.31e for snubbers not meeting the functional test acceptance criteria.

h. Functional Testing of Repaired and Replaced Snubbers

Snubbers which fail the visual inspection or the functional test acceptance criteria shall be repaired or replaced. Replacement snubbers and snubbers which have repairs which might affect the functional test results shall be tested to meet the functional test criteria before installation in the unit. Mechanical snubbers shall have met the acceptance criteria subsequent to their most recent service, and the freedom-of-motion test must have been performed within 12 months before being installed in the unit.

i. Snubber Service Life Program

The service life of hydraulic and mechanical snubbers shall be monitored to ensure that the service life is not exceeded between surveillance inspections. The maximum expected service life for various seals, springs, and other critical parts shall be determined and established based on engineering information and shall be extended or shortened based on monitored test results and failure history. Critical parts shall be replaced so that the maximum service life will not be exceeded during a period when the snubber is required to be OPERABLE. Part replacement shall be documented and the documentation shall be retained in accordance with Technical Specification 6.10.2.

Table 15.5.31-1
Number of Unacceptable Snubbers

POPULATION OR CATEGORY (NOTES 1 & 2)	COLUMN A EXTEND INTERVAL (NOTES 3 & 6)	COLUMN B REPEAT INTERVAL (NOTES 4 & 6)	COLUMN C REDUCE INTERVAL (NOTES 5 & 6)
1	0	0	1
80	0	0	2
100	0	1	4
150	0	3	8
200	2	5	13
300	5	12	25
400	8	18	36
500	12	24	48
750	20	40	78
1000 or greater	29	56	109

Note 1: The next visual inspection interval for a snubber population or category size shall be determined based upon the previous inspection interval and the number of unacceptable snubbers found during that interval. Snubbers may be categorized, based upon their accessibility during power operation, as accessible or inaccessible. These categories may be examined separately or jointly. However, the licensee must make and document that decision before any inspection and shall use that decision as the basis upon which to determine the next inspection interval for that category.

Note 2: Interpolation between population or category sizes and the number of unacceptable snubbers is permissible. Use next lower integer for the value of the limit for Columns A, B, or C if that integer includes a fractional value of unacceptable snubbers as determined by interpolation.

Note 3: If the number of unacceptable snubbers is equal to or less than the number in Column A, the next inspection interval may be twice the previous interval but not greater than 48 months.

Note 4: If the number of unacceptable snubbers is equal to or less than the number in Column B, but greater than the number in Column A, the next inspection interval shall be the same as the previous interval.

Note 5: If the number of unacceptable snubbers is equal to or greater than the number in Column C, the next inspection interval shall be two-thirds of the previous interval. However, if the number of unacceptable snubbers is less than the number in Column C but greater than the number in Column B, the next interval shall be reduced proportionally by interpolation, that is, the previous interval shall be reduced by a factor that is one-third of the ratio of the difference between the number of unacceptable snubbers found during the previous interval and the number in Column B to the difference in the numbers in Columns B and C.

Note 6: The provisions of Specification 4.0.2 are applicable for all inspection intervals up to and including 48 months.

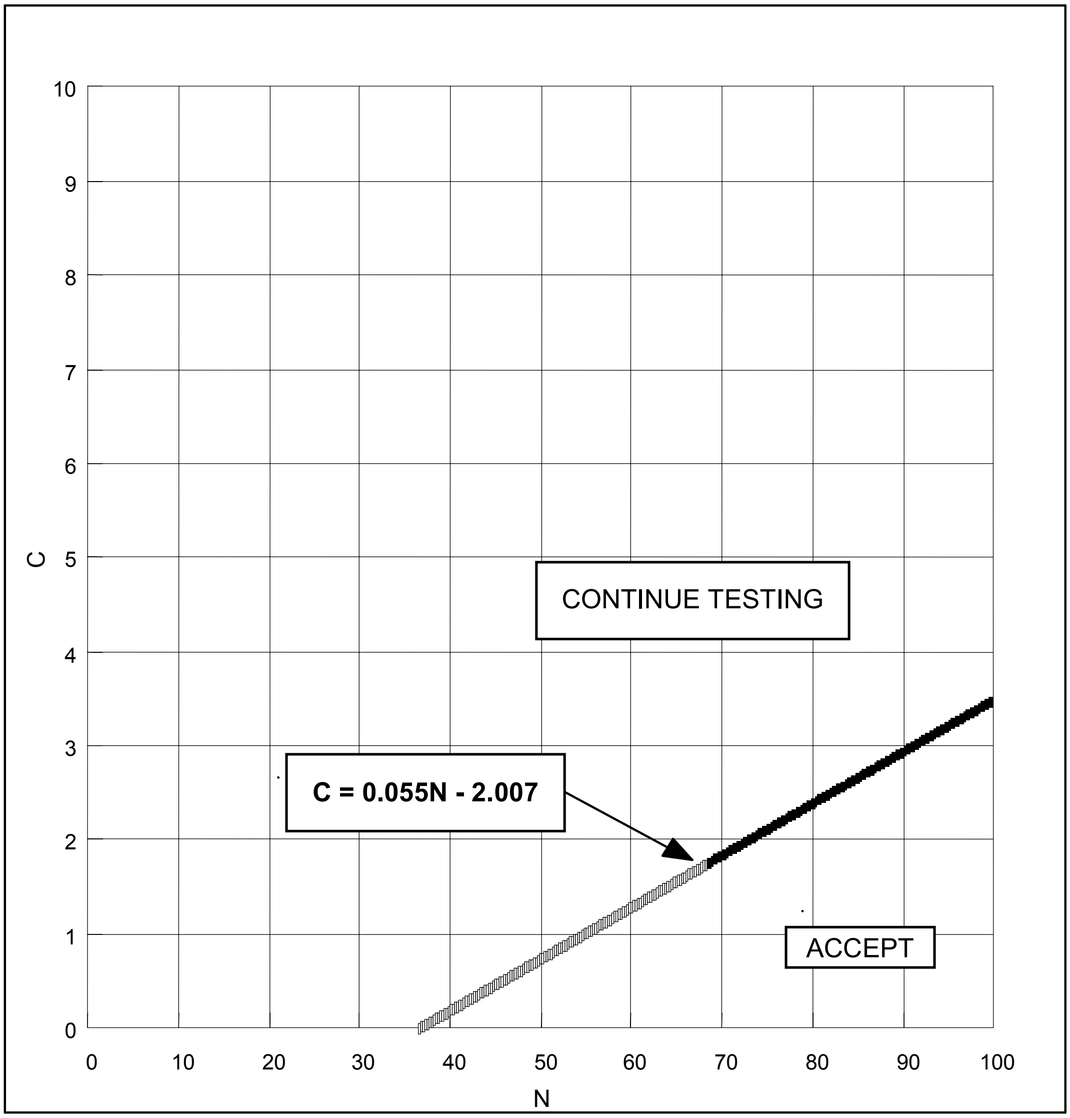

Figure 15.5.31-1
Sample Plan 2 for Snubber Functional Test

TECHNICAL REQUIREMENTS MANUAL (TRM) BASES

FOR

COMANCHE PEAK STEAM ELECTRIC STATION

UNITS 1 AND 2

(continued)

B 13.0 TECHNICAL REQUIREMENT (TR) LIMITING CONDITION FOR OPERABILITY (TR LCO) AND TECHNICAL REQUIREMENT SURVEILLANCE (TRS) APPLICABILITY

BASES

Related information is located in Technical Specification Bases 3.0.

B 13.1 REACTIVITY CONTROL SYSTEMS

TRB 13.1.31 Boration Injection System - Operating

BASES

BACKGROUND

The Boration Injection System is a subsystem of the Chemical and Volume Control System (CVCS). The CVCS regulates the concentration of chemical neutron absorber (boron) in the Reactor Coolant System (RCS) to control reactivity changes. The Boration Injection System ensures that negative reactivity control is available during each MODE of facility operation. The amount of boric acid stored in the borated water sources exceeds the amount required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay. The shutdown reactivity requirements are specified in Technical Specifications LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, "Control Bank Insertion Limits," and LCO 3.9.1, "Boron Concentration."

The components required to perform this function include: (1) borated water sources, (2) charging pumps, (3) separate flow paths, (4) boric acid transfer pumps, and (5) an emergency power supply from OPERABLE diesel generators.

Boric acid is stored in two boric acid tanks (BATs). Each BAT has a total volume of 46,000 gallons. The combined boric acid tank capacity is sized to store sufficient boric acid solution for refueling plus enough for a cold shutdown from full power operation immediately following refueling with the most reactive control rod not inserted. The two boric acid tanks are shared between Units 1 and 2. Two boric acid transfer pumps are provided for each unit with one pump normally required to provide boric acid to the suction header of the charging pumps, and the second pump in reserve. They are both aligned to take suction from separate boric acid tanks. On a demand signal by the reactor makeup controller, the pump starts and delivers boric acid to the suction header of the charging pumps. The pump can also be used to recirculate the boric acid tank fluid.

The Refueling Water Storage Tank (RWST) is also credited with being a required borated water source. The charging pumps and RWST are available to support the core cooling function in the event of a loss of coolant accident. Two charging pumps may be manually aligned, as necessary, to inject borated water from the RWST to the RCS for negative reactivity control. OPERABILITY of the charging pumps, the RWST, and appropriate core cooling flow paths are required as part of the Emergency Core Cooling System (ECCS). The Technical Specifications in Section 3.5 address the ECCS core cooling requirements.

(continued)

BASES

BACKGROUND (continued)

As listed below, the required indicated levels for the boric acid storage tanks and the RWST include allowances for required/analytical volume, unusable volume, measurement uncertainties (which include instrument error and tank tolerances, as applicable), margin, and other required volume.

Tank	MODES	Ind. Level	Unusable Volume (gal)	Required Volume (gal)	Measurement Uncertainty	Margin (gal)	Other (gal)
RWST	1, 2, 3, 4	95%	45,494	70,702	4% of span	N/A	357,535*
BAT	1, 2, 3, 4	50%	3,221	15,700	6% of span	N/A	N/A

* Additional volume required to meet Technical Specification 3.5.4.

Note: The level values for the Boric Acid Storage Tank (BAST) are non-conservative when using the gravity feed path from the BAST to the CCPs. The BAST levels are correct when using the path from the BAST to the Boric Acid Transfer Pump. The only place that it is incorrect is when using the BASTs to feed the CCPs through the gravity feed path when the BASTs have been sparged with nitrogen. This issue is being addressed in the corrective action program (SMF-2003-001212). In the interim, conservative limits for the BAST tanks levels have been identified in operations procedures. The conservative limits are:

Unit	Mode	BAT Temperature	Gravity Feed to CCP Required BAT Level
1	1-4	≤110°F	63%
1	1-4	≤95°F	56%
1	1-4	≤80°F	53%
2	1-4	≤110°F	95%
2	1-4	≤95°F	89%
2	1-4	≤80°F	86%

APPLICABLE SAFETY ANALYSES

The Boration Injection System is not assumed to be OPERABLE to mitigate the consequences of a design basis accident (DBA) or transient. However, the Boration Injection System satisfies, in part, General Design Criteria 26. In the event of a malfunction of the CVCS, which may cause a boron dilution event, manual operator action is to ensure the primary water makeup control valves in the Reactor Makeup System are closed. The Boration Injection System is required to be OPERABLE to provide sufficient boration flow paths to accomplish (1) chemical shim reactivity control, and (2) boration in the event SDM is discovered to be outside the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Technical Specification limit. The primary method of boration is performed from the BAT(s). An acceptable alternative form of boration is boron injection from the RWST. With the RCS average temperature above 200°F, two boron injection subsystems are required to ensure single functional capability in the event an assumed failure renders the flow path from one subsystem inoperable. The boration capability of either flow path is sufficient to provide the required SHUTDOWN MARGIN from expected operating conditions after xenon decay and cooldown to 200ºF. The maximum expected boration capability requirement occurs at EOL from full power equilibrium xenon conditions and requires 15,700 gallons of 7000 ppm borated water from the boric acid storage tanks or 70,702 gallons of 2400 ppm borated water from the refueling water storage tank (RWST).

LCO

Two boration injection subsystems are defined as:

1. Two of the following three injection flow paths: (a) the flow path from the boric acid storage tanks via either a boric acid transfer pump or a gravity feed connection and a charging pump to the RCS, and (b) two flow paths from the RWST via a centrifugal charging pump to the RCS, and,

2. Two centrifugal charging pumps (Note 2 allows the use of the positive displacement pump in lieu of a centrifugal charging pump in Mode 4), and,

3. One borated water source(s) (BAT and/or RWST) as required to support the injection flow paths of number 1 above.

The LCO is modified by Note 1, which allows operation in MODE 3 and 4 with CCPs made incapable of injecting pursuant to TS 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for up to 4 hours or until temperature of all RCS cold legs exceeds 375°F. This allowance is necessary since the LTOP arming temperature is below the MODE 3 boundary temperature of 350°F. Since TS 3.4.12 requires certain pumps be rendered incapable of injecting at and below the LTOP arming temperature, time is needed to restore the inoperable pumps to OPERABLE status following entry into MODE 3. This TRM Note is consistent with Note 2 to TS 3.5.2, "ECCS - Operating." The limitation for a maximum of two charging pumps to be OPERABLE and the requirement to verify one charging pump to be inoperable below 350°F provides assurance that a mass addition pressure transient can be relieved by the operation of a single PORV.

(continued)

BASES

APPLICABILITY

The OPERABILITY of two boration injection subsystems ensures that the Boration Injection System is available for reactivity control while the unit is operating in MODES 1, 2, 3 and 4.

ACTIONS

A.1

If one boration injection subsystem is inoperable (except due to an inoperable required charging pump), action must be taken to restore the subsystem to OPERABLE status. The 72 hour Completion Time takes into account the redundant capabilities afforded by the remaining OPERABLE boration injection subsystem and reasonable time for repairs. The Completion Time is consistent with the time allowed to restore an ECCS train to OPERABLE status.

B.1

If one boration injection subsystem is inoperable due to an inoperable charging pump, action must be taken to restore the required charging pump to OPERABLE status. The 7 day Completion Time takes into account the redundant capabilities afforded by the remaining OPERABLE charging pump and reasonable time for repairs.

C.1 and C.2

If both the required boration injection subsystems are inoperable the Boration Injection System may not be capable of supporting the negative reactivity control function. Therefore, immediate action must be taken to restore at least one subsystem to OPERABLE status. Action must continue until one boration subsystem is restored to OPERABLE status. If both the required boration injection subsystems are inoperable or if an inoperable boration injection subsystem(s) cannot be returned to OPERABLE status within the associated Completion Time for reasons other than the inoperability of a required centrifugal charging pump, an engineering evaluation under the Corrective Action Program (CAP) is immediately initiated, consistent with TR 13.0, Applicability NOTE 1. Using NRC guidance (e.g., Generic Letter 91-18) for resolution of degraded and nonconforming conditions, the engineering evaluation for continued operation should include a risk-informed assessment of current plant conditions (e.g., operating Mode, inoperable equipment, planned maintenance evolutions, etc.) and identify actions (compensatory and/or corrective) and associated completion times necessary to maintain the unit in a safe condition. Example compensatory actions while corrective actions are pursued might include

(continued)

BASES

ACTIONS (continued)

C.1 and C.2 (continued)

suspension of activities that could result in positive reactivity changes if in Modes 3 or 4 or suspending high risk work activities if maintaining the unit at power.

If a required centrifugal charging pump cannot be restored to OPERABLE status within the associated Completion Time, the requirements of Technical Specification 3.5.2, Condition C should be applied if in MODES 1, 2 or 3; Technical Specification 3.5.3, Condition C should be applied if in MODE 4.

The need for additional conditions and actions, beyond those described in Conditions A and B, are to be controlled in accordance with the corrective action program until the equipment is restored to OPERABLE status. The provision for using the corrective action program to address situations beyond the TRM LCO Conditions is not intended to be used merely as an operational convenience to extend allowed outage time intervals beyond those specified.

TECHNICAL REQUIREMENTS SURVEILLANCE

TRS 13.1.31.1

This TRS requires verification that the boration flow path for the required BAT(s) and boron solution temperature of the required BAT(s) is greater than 65°F. This temperature is sufficient to prevent boric acid crystal from precipitating for the highest allowed concentration of boric acid in the BATs.

The Frequency of 7 days for performance of the surveillance has been shown to be acceptable through operating experience and is consistent with the Technical Specification surveillance Frequency for verifying the RWST boron solution temperature.

TRS 13.1.31.2

This TRS requires a verification of the boron solution concentration of the required BAT(s) every 7 days. The minimum boron solution concentration requirements of the required BAT(s), along with the boron solution volume requirements, ensure cold shutdown boron weight is available for injection (i.e., SDM equivalent to 1.3% $\Delta k/k$ at 200°F). The Frequency to verify boron concentration is appropriate since the BAT boron solution concentration is normally stable and has been shown to be acceptable through operating experience. In addition, the Frequency is consistent with the Technical Specification surveillance Frequency for verifying the RWST boron solution concentration.

(continued)

BASES

TECHNICAL REQUIREMENTS SURVEILLANCE (continued)

TRS 13.1.31.3

This surveillance requires verification that the BAT boron solution volume is at least 50%. The minimum boron solution volume, along with the boron solution concentration requirements, ensures cold shutdown boron weight is available for injection (i.e., SDM equivalent to 1.3% $\Delta k/k$ at 200°F). The boron solution volume limit of the RWST is specified in Technical Specification 3.5.4 and ensures sufficient volume is available to inject the required cold shutdown boron weight including any unusable volume. The 7 day Frequency to verify boron solution volume is appropriate since the BAT volumes are normally stable and has been shown to be acceptable through operating experience. In addition, the Frequency is consistent with the Technical Specification surveillance Frequency for verifying the RWST boron solution volume.

Note: The level values for the Boric Acid Storage Tank (BAST) are non-conservative when using the gravity feed path from the BAST to the CCPs. The BAST levels are correct when using the path from the BAST to the Boric Acid Transfer Pump. The only place that it is incorrect is when using the BASTs to feed the CCPs through the gravity feed path when the BASTs have been sparged with nitrogen. This issue is being addressed in the corrective action program (SMF-2003-001212). In the interim, conservative limits for the BAST tanks levels have been identified in operations procedures. The conservative limits are:

Unit	Mode	BAT Temperature	Gravity Feed to CCP Required BAT Level
1	1-4	≤110°F	63%
1	1-4	≤95°F	56%
1	1-4	≤80°F	53%
2	1-4	≤110°F	95%
2	1-4	≤95°F	89%
2	1-4	≤80°F	86%

TRS 13.1.31.4

Verifying the correct alignment for each boration injection subsystem manual, power operated, and automatic valve provides assurance that the proper flow paths exist for boration injection subsystem operation. This TRS does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. A valve may be in the non boration injection position provided the valve is capable of being

(continued)

BASES

TECHNICAL REQUIREMENTS SURVEILLANCE (continued)

TRS 13.1.31.4 (continued)

manually repositioned to the boration injection position. This TRS does does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This TRS does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve position.

TRS 13.1.31.5

Verification that the flow path from the BATs delivers at least 30 gpm to the RCS demonstrates that gross degradation of the boric acid transfer pumps, CCPs, crystallization of boric acid in the boration injection subsystems, and other hydraulic component problems have not occurred. The 18 month Frequency was developed considering it is prudent that this Surveillance be performed during a plant outage. This is due to the plant conditions needed to perform the TRS and the potential for unplanned plant transients if the TRS is performed with the reactor at power.

TRS 13.1.31.6

Periodic surveillance testing of CCPs to detect gross degradation caused by impeller structural damage or other hydraulic component problems is performed in accordance with Section XI of the American Society of Mechanical Engineers (ASME) Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. The activities and Frequencies necessary to satisfy the requirements of this TRS are accomplished with the performance of SR 3.5.2.4.

TRS 13.1.31.7

Periodic surveillance testing of the positive displacement pump is performed to ensure that it meets the minimum flow requirements of the Boron Injection System when used in lieu of a CCP in Mode 4. This is accomplished by verifying that it delivers at least 30 gpm from a BAT to the RCS per TRS 13.1.31.5. The 18 month Frequency was developed considering it is prudent that this Surveillance be performed during a plant outage.

B 13.1 REACTIVITY CONTROL SYSTEMS

TRB 13.1.32 Boration Injection System - Shutdown

BASES

BACKGROUND

A description of the Boration Injection System is provided in the Bases for TR 13.31.1, “Boration Injection System - Operating.”

As listed below, the required indicated levels for the boric acid storage tanks and the RWST include allowances for required/analytical volume, unusable volume, measurement uncertainties (which include instrument error and tank tolerances, as applicable), margin, and other required volume.

Tank	MODES	Ind. Level	Unusable Volume (gal)	Required Volume (gal)	Measurement Uncertainty	Margin (gal)	Other (gal)
RWST	5, 6	24%	98,900	7,113	4% of span	10,293	N/A
BAT	5, 6 5, 6 (gravity feed)	10% 20%	3,221 3,221	1,100 1,100	6% of span 6% of span	N/A 3,679	N/A N/A

Note: The level values for the Boric Acid Storage Tank (BAST) are non-conservative when using the gravity feed path from the BAST to the CCPs. The BAST levels are correct when using the path from the BAST to the Boric Acid Transfer Pump. The only place that it is incorrect is when using the BASTs to feed the CCPs through the gravity feed path when the BASTs have been sparged with nitrogen. This issue is being addressed in the corrective action program (SMF-2003-001212). In the interim, conservative limits for the BAST tanks levels have been identified in operations procedures. The conservative limits are:

Unit	Mode	BAT Temperature	Gravity Feed to CCP Required BAT Level
1	5-6	≤110°F	33%
1	5-6	≤95°F	26%
1	5-6	≤80°F	23%
2	5-6	≤110°F	65%
2	5-6	≤95°F	59%
2	5-6	≤80°F	56%

(continued)

BASES

APPLICABLE SAFETY ANALYSES	The boration subsystem is not assumed to be OPERABLE to mitigate the consequences of a DBA or transient. However, the boration injection subsystem satisfies, in part, General Design Criteria 26. In the case of a malfunction of the Chemical and Volume Control System (CVCS), which caused a boron dilution event, an appropriate response by the operator is to isolate the source of primary water makeup. The boron injection capability requirement in conjunction with the cooldown capability identified in Branch Technical Position RSB 5-1 ensures the ability to reach cold shutdown conditions within a reasonable time period. In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the Reactor Coolant System (RCS) as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid storage tank, or the Reactor Water Storage Tank (RWST). The operator should borate with the best source available for the plant conditions. With the RCS temperature below 200°F, one boron injection subsystem is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the additional restrictions prohibiting CORE ALTERATIONS and positive reactivity changes in the event the single boron injection subsystem becomes inoperable. The TS 3.4.12 limitation for a maximum of two charging pumps to be OPERABLE below 350°F provides assurance that a mass addition pressure transient can be relieved by the operation of a single PORV. The boron capability required below 200°F is sufficient to provide the required SHUTDOWN MARGIN after xenon decay and cooldown from 200°F to 140°F. This condition requires either 1,100 gallons of 7000 ppm borated water from the boric acid storage tanks or 7,113 gallons of 2400 ppm borated water from the RWST.
LCO	In MODES 5 and 6, one boration injection subsystem is required to be OPERABLE to provide a boration flow path to allow immediate boration in the event SDM is discovered to be outside the Technical Specification limit. To ensure reliability is maintained in the event of a loss of the normal AC power source, the required boration injection subsystem must be capable of being powered from an OPERABLE emergency power source. One boration injection subsystem is acceptable without single failure consideration on the basis of the relatively stable reactivity condition of the reactor.

(continued)

BASES

LCO (continued)

For the required boration injection subsystem to be considered OPERABLE, all of the following are required:

a. An injection flow path (1) from the required boric acid storage tank via either a boric acid transfer pump or a gravity feed connection and a charging pump to the RCS, or (2) from the RWST via a charging pump to the RCS, and

b. Either a centrifugal charging pump or positive displacement charging pump, and

c. A borated water source from either a BAT or the RWST.

APPLICABILITY

In MODE 5 SDM is required to ensure the reactor will be held subcritical with margin for the most reactive Rod Control Cluster Assembly fully withdrawn. SDM is required in MODE 6 to prevent an open vessel inadvertent criticality. As such, the OPERABILITY of one boron injection subsystem ensures reactivity control is available while in MODES 5 and 6. Boration Injection System requirements in MODES 1, 2, 3, and 4 are addressed in TR 13.1.31, "Boration Injection System - Operating."

ACTIONS

A. 1

With the required boration injection subsystem inoperable or the boration injection subsystem not capable of being powered by an OPERABLE emergency power source, the operator must immediately suspend operations involving positive reactivity additions that could result in loss of required SDM or loss of required boron concentration. The Required Actions minimize the potential for inadvertent criticality.

Suspending positive reactivity additions that could result in failure to meet the minimum SDM or boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory may allow dilution of the RCS but the source of makeup water is required to contain sufficient boron concentration such that when mixed with the RCS inventory the resulting boron concentration in the RCS meets the minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

(continued)

BASES

TECHNICAL REQUIREMENTS SURVEILLANCE

TRS 13.1.32.1

This TRS requires verification that the boron solution temperature of the required RWST is greater than 40°F. This temperature is sufficient to prevent boric acid crystals from precipitating out of solution at the highest allowed concentration of boric acid in the RWST.

The Frequency of 24 hours for performance of the surveillance has been shown to be acceptable through operating experience and is consistent with the Technical Specification surveillance Frequency for verifying the RWST boron solution temperature.

TRS 13.1.32.2

See Bases for TRS 13.1.31.1

TRS 13.1.32.3

See Bases for TRS 13.1.31.2

TRS 13.1.32.4 and TRS 13.1.32.5

This surveillance requires verification that the BAT boron solution volume is at least 10% when using the boric acid pump from the boric acid storage tank or 20% when using gravity feed from the boric acid storage tank. The minimum boron solution volume, along with the boron solution concentration requirements, ensures cold shutdown boron weight is available for injection (e.g., SDM equivalent to 1.3% $\Delta k/k$ at 200°F). The 7 day Frequency to verify boron solution volume is appropriate since the BAT volumes are normally stable and has been shown to be acceptable through operating experience. In addition, the Frequency is consistent with the Technical Specification surveillance Frequency for verifying the RWST boron solution volume.

(continued)

BASES

TECHNICAL REQUIREMENTS SURVEILLANCE (continued)

TRS 13.1.32.4 and TRS 13.1.32.5 (continued)

Note: The level values for the Boric Acid Storage Tank (BAST) are non-conservative when using the gravity feed path from the BAST to the CCPs. The BAST levels are correct when using the path from the BAST to the Boric Acid Transfer Pump. The only place that it is incorrect is when using the BASTs to feed the CCPs through the gravity feed path when the BASTs have been sparged with nitrogen. This issue is being addressed in the corrective action program (SMF-2003-001212). In the interim, conservative limits for the BAST tanks levels have been identified in operations procedures. The conservative limits are:

Unit	Mode	BAT Temperature	Gravity Feed to CCP Required BAT Level
1	5-6	≤110°F	33%
1	5-6	≤95°F	26%
1	5-6	≤80°F	23%
2	5-6	≤110°F	65%
2	5-6	≤95°F	59%
2	5-6	≤80°F	56%

TRS 13.1.32.6 and TRS 13.1.32.7

This surveillance requires verification that the RWST solution boron concentration is at least 2400 ppm and the indicated boron solution volume is at least 24%. The minimum boron solution volume, along with the boron solution concentration requirements, ensures cold shutdown boron weight is available for injection (e.g., SDM equivalent to 1.3% Δk/k at 200°F). The 7 day Frequency to verify boron solution volume is appropriate since the RWST volume is normally stable and has been shown to be acceptable through operating experience. In addition, the Frequency is consistent with the Technical Specification surveillance Frequency for verifying the RWST boron solution concentration and volume in MODES 1, 2, 3 and 4.

TRS 13.1.32.8

See Bases for TRS 13.1.31.4

TRS 13.1.32.9

See Bases for TRS 13.1.31.7

TRS 13.1.32.10

See Bases for TRS 13.1.31.6

B 13.1 REACTIVITY CONTROL SYSTEMS

TRB 13.1.37 Rod Group Alignment Limits and Rod Position Indicator

BASES

Related requirements/information is located in Technical Specification Bases Section 3.1.4.

B 13.1 REACTIVITY CONTROL SYSTEMS

TRB 13.1.38 Control Bank Insertion Limits

BASES

Related requirements/information is found in Technical Specification Bases Section 3.1.6.

B 13.1 REACTIVITY CONTROL SYSTEMS

TRB 13.1.39 Rod Position Indication - Shutdown

BASES

Related requirements/information is located in Technical Specification Bases Section 3.1.7.

The following discussion is provided to clarify TR 13.1.39 APPLICABILITY.
Control rod testing includes the following independent but related activities:

1. Digital Position Indication System (DRPI) testing per SR 3.1.7.1 and TRS 13.1.39.1,

2. Control rod drop timing per SR 3.1.4.3, and

3. Control Rod Drive Mechanism (CRDM) step traces, which is not a Surveillance Requirement, but is an integral part of control rod functional testing.

These activities may be performed independently or concurrently.

If Keff is maintained ≤ 0.95, and no more than one shutdown or control bank is withdrawn from the fully inserted position, control rods may be withdrawing in MODES 3, 4, and 5 for any reason. The limitations on Keff and control rod bank withdrawal are consistent with assumptions made in the design calculations that determine the boron concentration necessary to provide assurance that inadvertent criticality will be avoided.

Once DRPI is declared OPERABLE for all shutdown and control banks, the requirement for Keff ≤ 0.95 is removed. This allows for significantly reduced boron concentration in preparation for plant startup activities.

One CPSES approved method of measuring rod drop times is an established industry method that produces DRPI coil voltage traces. The standard procedure withdraws one shutdown or control bank at a time. DRPI shall be available (but may or may not be OPERABLE) during the withdrawal of the rods, with the limitations on Keff described above. The data necessary to generate DRPI coil voltage traces is obtained from the induced voltage in the position indicator coils as the rod is dropped. The induced voltage is small compared to normal voltage and cannot be observed if DRPI remains energized and OPERABLE. With the rods fully withdrawn, DRPI is de-energized, rendering it inoperable, and the reactor trip breakers are opened to drop the rods. Once the rods have been dropped, DRPI is energized again.

Another CPSES approved method of measuring rod drop times uses the Plant Process Computer (PPC). The PPC method relies on normal operating DRPI indications to determine the time a control rod reaches a specified position. DRPI shall be available (but may or may not be OPERABLE) during the withdrawal of the rods, with the limitations on Keff described above. DRPI remains energized during testing.

B 13.2 POWER DISTRIBUTION LIMITS

TRB 13.2.31 Moveable Incore Detection System

BASES

The OPERABILITY of the movable incore detectors with the specified minimum complement of equipment ensures that the measurements obtained from use of this system accurately represent the spatial neutron flux distribution of the core. The OPERABILITY of this system is demonstrated by irradiating each detector used and determining the acceptability of its voltage curve. For the purpose of measuring $F_Q(Z)$ or $F^N_{\Delta H}$ a full incore flux map is used. Quarter-core flux maps, as defined in WCAP-8648, June 1976, may be used in recalibration of the Excore Neutron Flux Detection System, and full incore flux maps or symmetric incore thimbles may be used for monitoring the QUADRANT POWER TILT RATIO when one Power Range channel is inoperable.

B 13.2 POWER DISTRIBUTION LIMITS

TRB 13.2.32 Axial Flux Difference (AFD)

BASES

Related information is located in Technical Specification Bases Section 3.2.3
A Note in the Frequency for Technical Requirement Surveillance (TRS) 13.2.32.1 relaxes the requirement of logging Axial Flux Difference (AFD) data for 24 hours after the AFD Monitor is restored. The plant computer is capable of retaining AFD historical data in the event of a computer failure and will accept new data after it is restored to service such that it does not need to operate for 24 hours in order to create the 24 hour history required for AFD monitoring.

In the event the AFD Monitor Alarm is inoperable, TRM Surveillance 13.2.32.1 requires logging the AFD value with a specific frequency. The purpose of the logging function is for the calculation of AFD penalty minutes for which a 24 hour history is required. The requirement to periodically monitor the AFD indication is not relaxed nor is the requirement to comply with the AFD penalty minute limitations of TS 3.2.3 affected.

B 13.2 POWER DISTRIBUTION LIMITS

TRB 13.2.33 Quadrant Power Tilt Ratio (QPTR) Alarm

BASES

Related information is located in Technical Specification Bases Section 3.2.4

B 13.3 INSTRUMENTATION

TRB 13.3.1 Reactor Trip System (RTS) Instrumentation Response Times

BASES

The bases for the Reactor Trip System are contained in the CPSES Technical Specifications. The measurement of response time at the specified frequencies provides assurance that the Reactor trip actuation associated with each channel is completed within the time limit assumed in the safety analyses. No credit was taken in the analyses 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 measurements provided that such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either: (1) in place, onsite, or offsite test measurements, or (2) utilizing replacement sensors with certified response time.

The overall response time limit for the overtemperature N-16 reactor trip function is 8 seconds, as noted in TRM Table 13.3.1-1, Item 6. Note 2 clarifies that a maximum of 6 seconds is allowed for the RTD/thermal well response time, as described in FSAR Table 15.0-4. Taken together with the overall response time requirement of 8 seconds, the allowed response time components (RTD/thermal well and “electronic”) are specified in a manner consistent with the accident analyses.

B 13.3 INSTRUMENTATION

TRB 13.3.2 Engineered Safety Features Actuation System (ESFAS) Instrumentation Response Times

BASES

The bases for the Engineered Safety Features Actuation System are contained in the CPSES Technical Specifications. The measurement of response time at the specified frequencies provides assurance that the Engineered Safety Features actuation associated with each channel is completed within the time limit assumed in the safety analyses. No credit was taken in the analyses 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 measurements provided that such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either: (1) in place, onsite, or offsite test measurements, or (2) utilizing replacement sensors with certified response time.

B 13.3 INSTRUMENTATION

TRB 13.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation Response Times

BASES

TRM Table 13.3.5-1 contains the initiation signals and function response time limits for the LOP DG Start Instrumentation. The response time limits for each function are consistent with the analytical limits presented in the FSAR, Chapter 15.

The Chapter 15 Accident Analysis contains separate analyses for the Design Basis Accident (DBA) and Loss of Offsite Power (LOOP) events. CPSES assumes these events to occur independently of each other and does not postulate the simultaneous occurrence of a Design Basis Accident (DBA) and a Loss of Offsite Power.

For purposes of accident analysis however, CPSES conservatively assumes a LOOP concurrent with a turbine trip. All DBAs, with the exception of Feedwater Line Break (FWLB), generate an immediate Safety Injection Actuation Signal (SIAS) with a resultant DG start initiation, reactor trip, turbine trip, and an assumed LOOP. For the FWLB, the DG is postulated to start from a LOOP signal. The response times for the LOP DG Start Instrumentation assure that on a LOOP, the DG will start in sufficient time to meet the 60 second requirement for Auxiliary Feedwater Pump (AFWP) running for mitigation of the FWLB.

CPSES provides for equipment protection due to sustained degraded or low grid voltage conditions. However, the CPSES accident analysis does not assume degraded grid conditions to occur simultaneously with a DBA. For conservatism, safety buses are promptly isolated from an established degraded grid or low grid condition upon the subsequent occurrence of an SIAS. Response time requirements for LOP DG Start Instrumentation assure that, on occurrence of an SIAS subsequent to an established degraded or low grid condition, the safety buses are isolated from the degraded or low grid condition in sufficient time to allow for the closure of the DG output circuit breaker to the safety bus within 10 seconds from the receipt of the SIAS start signal by the DG.

The measurement of response time at the specified frequencies provides assurance that the Loss of Power features associated with each channel is completed within the time limit assumed in the safety analyses. No credit was taken in the analyses 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 measurements provided that such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either: (1) in place, onsite, or offsite test measurements, or (2) utilizing replacement sensors with certified response time.

B 13.3 INSTRUMENTATION

TRB 13.3.31 Seismic Instrumentation

BASES

The OPERABILITY of the seismic monitoring system ensures that sufficient capability is available to promptly determine whether the OBE has been exceeded and to collect information to evaluate the response of features important to safety. This capability is required pursuant to Appendix A of 10CFR100. The instrumentation provided meets the intent of Regulatory Guide 1.12, “Instrumentation for Earthquakes,” April 1974, as described in the FSAR. The seismic monitoring system will record and analyze a seismic event to determine OBE exceedance in accordance with the requirements described in the FSAR.

B 13.3 INSTRUMENTATION

TRB 13.3.32 Reactor Trip System (RTS) Instrumentation - Source Range Neutron Flux

BASES

Technical Specification 3.3.1 requires the source range reactor trip function to be OPERABLE in Modes 3, 4 and 5, when the Rod Control System is capable of rod withdrawal or all control rods are not fully inserted. However, when in the converse condition, i.e., the Rod Control System is not capable of rod withdrawal and all control rods are fully inserted, the source range neutron flux channels are only required to be available to monitor the reactivity state of the core; however, no reactor trip function is required.

The primary function of the source range neutron flux monitors in Modes 3, 4, and 5, when the source range reactor trip function is not required to be OPERABLE per TS 3.3.1, is to provide a visual signal to alert the operator to unexpected changes in core reactivity such as an inadvertent boron dilution accident, an unexpected moderator temperature change or an improperly loaded fuel assembly. Either the set of two Westinghouse-supplied BF_3 source range detectors or the set of two Gamma-Metrics Neutron Flux Monitoring System channels may be used to perform this reactivity-monitoring function.

The CPSES design includes two separate systems for monitoring the neutron flux. The Westinghouse portion of the system consists of three instrumentation ranges: the Source Range, Intermediate Range and the Power Range. Each portion consists of detectors, power supplies, signal processing equipment and indicators. The Westinghouse source range neutron flux monitors provide audio and visual indications of neutron count rate. The audible output provides a warning in the main control room and containment of any potentially hazardous condition. However, with the implementation of CPSES TS Amendment 64, (the Improved Technical Specifications), the audible count indication was deleted as a requirement for the source range neutron flux monitors.

A separate Gamma-Metrics Neutron Flux Monitoring System (NFMS) is installed to satisfy the requirements of Regulatory Guide 1.97, “Instrumentation For Light-Watered-Cooled Nuclear Power Plants To Assess Plant And Environs Conditions During And Following An Accident.” The Gamma-Metrics NFMS monitors neutron flux from the source range through 200% Rated Thermal Power (RTP) during all Modes of plant operation. This system utilizes two separate (Class 1E) fission chamber neutron detectors for all ranges of neutron flux indication. Specific requirements for this function of the Gamma-Metrics NFMS are contained in Technical Specification 3.3.4.

Both the Westinghouse source range neutron flux monitors and the Gamma-Metrics Neutron Monitoring System are functionally equivalent and both are qualified to Class 1E standards.

(continued)

BASES (continued)

The channel check performed on the Gamma-Metrics detectors verifies the actual process signal as it is input to the sensor. Because of the inherent nature of the statistical emission of source range neutrons from the reactor core, the process signal provides an observable fluctuation that is visible on the end devices (control room instrumentation). Furthermore, there are no alarm, interlock or trip functions associated with these channels. Therefore, a Channel Operability Test is not required for the Gamma-Metrics detectors.

Related information is located in Technical Specification Bases 3.3.1

B 13.3 INSTRUMENTATION

TRB 13.3.33 Turbine Overspeed Protection

BASES

BACKGROUND

This specification is provided to ensure that the turbine overspeed protection instrumentation and the turbine Stop and Control Valves are operable and will protect the turbine from excessive overspeed. Protection from excessive overspeed is necessary to prevent the generation of potentially damaging missiles which could impact and damage safety-related components, equipment and structures. Turbine overspeed is limited by rapid closure of the turbine Stop or Control Valves whenever turbine power exceeds generator output, as would exist immediately following a load rejection.

The Electrohydraulic Control (EHC) System is the primary means of limiting the extent of an overspeed event, with the turbine Overspeed Protection System as a backup. The EHC System is designed to limit transient overspeed to less than 110% of rated speed after a full load rejection by closing both the High Pressure (HP) and Low Pressure (LP) Control Valves. This function of the EHC System is performed by the normal speed/load control logic in conjunction with additional protection logic that ensures closure of all control valves under certain load rejection scenarios (Reference 1).

To minimize the possibility of a component failure resulting in a loss of the control function, the EHC System utilizes triple redundant speed and load inputs, dual redundant digital controller processors, and dual redundant outputs (amplifiers, proportional valves, and follow-up piston banks) to the Control Valves.

In the unlikely event that the EHC System fails to limit the overspeed condition, the Overspeed Protection System will act to limit the overspeed to less than 120% of rated speed.

The Overspeed Protection System is made up of the following basic component groups:

- Independent and redundant speed sensors and associated signal processing instrumentation, including bistables, provide individual speed channel trip signals to the Turbine AG-95F Digital Protection System and the hardware overspeed trip system (both described below) whenever turbine speed exceeds 1980 rpm.

(continued)

BASES

BACKGROUND (continued)

- The Turbine AG-95F Digital Protection System consists of three independent and redundant trains of equipment, including input modules, dual redundant automation processors and associated software, output modules, and output relays. The AG-95F System is a fail-safe system in that all inputs and outputs are normally energized in the non-tripped state.

  Each train of the AG-95F System processes the individual speed channel trip signals using 2 of 3 trip logic. When the trip logic is satisfied, the associated output relays de-energize, each one subsequently de-energizing its associated Turbine Trip Block solenoid valve.

- The Relay Protection System consists of relay logic and output relays that are diverse from, and completely bypass, the AG-95F Digital Protection System described above. The logic and output relays are normally energized in the non-gripped state.

  The relay logic processes the individual speed channel trip signals using 2 of 3 trip logic. When the trip logic is satisfied, all three output relays de-energize, each one subsequently de-energizing its associated Turbine Trip Block solenoid valve.

- The Turbine Trip Block utilizes three independent and redundant solenoid valves to actuate associated hydraulic pistons that are configured in a manner that provides a hydraulic 2 of 3 trip logic. When any two of the three solenoid valves de-energize, actuation of the associated pistons rapidly de-pressurizes the turbine Trip Fluid System, causing all turbine Stop and Control Valves to close. De-energization of a single solenoid valve will not trip the turbine.

The Overspeed Protection System consists of two redundant and diverse sub-systems, the Hardware Overspeed Sub-system and the Software Overspeed Sub-system, that are configured using the component groups described above. Either of these sub-systems can independently trip the turbine.

The Hardware Overspeed Sub-system utilizes a set of three dedicated speed channels, each of which provides a trip signal to the Relay Protection System. Upon receipt of trip signals from any two of these speed channels, the relay logic de-energizes all three output relays which subsequently de-energize all three Turbine Trip Block solenoid valves, causing the turbine to trip.

(continued)

BASES

BACKGROUND (continued)

As a backup, the three dedicated Hardware Overspeed Sub-system speed channels also provide trip signals to all three of the AG-95F System protection trains. Upon receipt of trip signals from any two of these speed channels, the output relay of each protection train is de-energized, subsequently de-energizing all three Turbine Trip Block solenoid valves, causing the turbine to trip.

The Software Overspeed Sub-system utilizes a second set of three dedicated speed channels which provide input to all three of AG-95F System protection trains. Upon receipt of trip signals from any two of these speed channels, the output relay of each protection train is de-energized, subsequently de-energizing all three Turbine Trip Block solenoid valves, causing the turbine to trip. The Software Overspeed System speed channels also provide speed signals to the EHC System as described above.

The design of the Overspeed Protection System includes several testing features that are used to ensure OPERABILITY of the system. These features include three Automatic Turbine Tester (ATT) tests that are manually initiated by the operator. They also include a test that is automatically executed by the system to ensure OPERABILITY of the speed channel instrumentation.

The ATT HP and LP Valve Tests cycle all Stop and Control Valves to ensure reliability and continuity of service. The HP and LP Stop Valve closure times are also verified to be within required response times (500 and 1500 msec, respectively). These tests cycle one pair of Stop and Control Valves at a time, so they may be performed with the plant on-line below approximately 85% power.

The ATT Turbine Trip Block Test de-energizes each Turbine Trip Block solenoid valve and verifies that the associated hydraulic piston moves to the trip position. The solenoid valve/piston pairs are sequentially tested one at a time, until all three are tested. Each pair is reset prior to testing the subsequent pair. Since only one solenoid valve/piston pair is tested at a time, the Trip Fluid System is never de-pressurized, and the turbine does not trip.

Each of the six individual speed channels (three for the Hardware Overspeed Sub-system and three for the Software Overspeed Sub-system), is automatically tested once every 24 hours when turbine speed is >40 rpm. These tests verify that the speed channels trip when speed is simulated above 1980 rpm. The tests are initiated by the AG-95F

(continued)

BASES

BACKGROUND (continued)

System in a manner that precludes two speed channels from being tested at the same time. If desired, the speed channel tests may also be initiated by the operator.

Alarms are provided to alert the operator in the event of a fault/failure is detected during the execution of any of the aforementioned tests.

APPLICABLE SAFETY ANALYSES

The Overspeed Protection System is required to be OPERABLE to provide sufficient protection against generation of potentially damaging missiles which could impact and damage safety-related components, equipment and structures. The turbine missile analysis is presented in Reference 2. Using References 3 through 5 as a basis, this analysis concludes that the risk for loss of an essential system due to a turbine missile event is acceptably low.

The robust design of the Overspeed Protection System, with its multiple speed channels, diverse hardware and software logic, and multiple Turbine Trip Block solenoid valves/hydraulic pistons, meets the intent of SRP 10.2 Part III for redundancy and independence.

LCO

The Turbine Overspeed Protection Sub-systems are the Hardware Overspeed Sub-system and the Software Overspeed Sub-system, one of which shall be OPERABLE.

The robust design of these sub-systems allows for the failure of individual components without rendering the sub-system(s) inoperable. Specifically, the minimum operability requirements for the Hardware Overspeed Sub-system include:

- two OPERABLE dedicated hardware speed channels, and associated OPERABLE hardware relay logic with two OPERABLE output relays and associated Turbine Trip Block solenoid valves/hydraulic pistons

  OR

- two OPERABLE dedicated hardware speed channels and two associated OPERABLE AG-95F System trains, including output relays and associated Turbine Trip Block solenoid valves/ hydraulic pistons

(continued)

BASES

LCO (continued)

The minimum operability requirements for the Software Overspeed Sub-system include:

- two OPERABLE dedicated software speed channels and two associated OPERABLE AG-95F System trains, including output relays and associated Turbine Trip Block solenoid valves/ hydraulic pistons

Individual component failures that do not render the sub-system(s) inoperable are addressed under the Corrective Action Program (CAP) with restoration times commensurate with the severity of the failure and the operational impact associated with the rework or repair.

Furthermore, component failures that result in rendering only one Overspeed Protection Sub-system inoperable are also addressed under the CAP with restoration times commensurate with the severity of the failure and the operational impact associated with the rework or repair.

The OPERABILITY of one Overspeed Protection Sub-system ensures that the Overspeed Protection System is available to prevent an overspeed event while the unit is operating in MODE 1, 2, and 3 with steam available to roll the turbine. The APPLICABILITY is modified by a Note specifying that Overspeed Protection Sub-system OPERABILITY is not required in MODE 2 and 3 if the turbine is isolated from the steam supply by closing all Main Steam Isolation Valves and associated bypass valves.

ACTIONS

A.1, A.2, and A.3

This ACTION is modified by a Note that specifies that separate Condition entries are allowed for each steam line if valves are inoperable in multiple steam lines.

If an HP Stop or Control Valve is inoperable such that it is not capable of properly isolating the steam line to the turbine in response to an overspeed event, action must be taken to restore the valve(s) to OPERABLE status. Failure to restore the valve(s) to OPERABLE status within 72 hours requires that compensatory action be taken within the following 6 hours to ensure that the affected steam line is isolated by other means.

(continued)

BASES

ACTIONS (continued)

A.1, A.2, and A.3 (continued)

The 72 hour Completion Time for restoring the valve(s) takes into account the OPERABILITY of the remaining valve in the affected steam line and reasonable time for rework or repair. The 6 hour compensatory action Completion Time is reasonable, based on operating experience, for reaching the required unit conditions from full power operation in an orderly manner and without challenging unit systems.

B.1, B.2, and B.3

This ACTION is modified by a Note that specifies that separate Condition entries are allowed for each steam line if valves are inoperable in multiple steam lines.

If an LP Stop or Control Valve is inoperable such that it is not capable of properly isolating the steam line to the turbine in response to an overspeed event, action must be taken to restore the valve(s) to OPERABLE status. Failure to restore the valve(s) to OPERABLE status within 72 hours requires that compensatory action be taken within the following 6 hours to ensure that the affected steam line is isolated by other means.

The 72 hour Completion Time for restoring the valve(s) takes into account the OPERABILITY of the remaining valve in the affected steam line and reasonable time for rework or repair. The 6 hour compensatory action Completion Time is reasonable, based on operating experience, for reaching the required unit conditions from full power operation in an orderly manner and without challenging unit systems.

C.1

If both Overspeed Protection Sub-systems are inoperable, such that neither is capable of initiating a turbine trip in response to an overspeed event, action must be taken within 6 hours to isolate the turbine from the steam supply.

The 6 hour Completion Time for isolating the turbine from the steam supply is reasonable, based on operating experience, for reaching the required unit conditions from full power operation in an orderly manner and without challenging unit systems.

(continued)

BASES

ACTIONS (continued)

D.1, D.2, and D.3

In the event that the aforementioned ACTIONS and associated Completion Times cannot be satisfied, action must be initiated within 1 hour to place the unit in a lower MODE, with subsequent action to place the unit in MODE 3 within the following 6 hours and to place the unit in MODE 4 within 6 hours after entering MODE 3. The need to perform these actions would most likely result from the inability to isolate the turbine from the steam supply. Placing the unit in MODE 4 will reduce steam pressure to the point where there is insufficient motive force to overspeed the turbine, even if it is not isolated from the steam generators.

The Completion Times are reasonable, based on operating experience, for reaching MODE 3 and MODE 4 from full power operation in an orderly manner and without challenging unit systems.

TECHNICAL REQUIREMENTS SURVEILLANCE

The TRS 13.3.33 requirements are modified by a Note that specifies that the provisions of TRS 13.0.4 are not applicable.

TRS 13.3.33.1

This TRS specifies testing of the Turbine Trip Block using the Automatic Turbine Tester (ATT). This test de-energizes each Turbine Trip Block solenoid valve and verifies that the associated hydraulic piston moves to trip position. The solenoid valve/piston pairs are sequentially tested one at a time, until all three are tested. Each pair is reset prior to testing the subsequent pair. Since only one solenoid valve/piston pair is tested at a time, the Trip Fluid System is never de-pressurized, and the turbine does not trip.

The 14 day test Frequency is based on the assumptions in the analyses presented in References 2 and 4.

TRS 13.3.33.2

This TRS specifies testing of the turbine HP and LP Stop and Control Valves using the ATT. These tests cycle all Stop and Control Valves to ensure reliability and continuity of service. The HP and LP Stop Valve closure times are also verified to be within required response times (500 and 1500 msec, respectively). These tests cycle one pair of Stop and Control Valves at a time, so they may be performed with the plant on-line below approximately 85% power.

The 12 week test Frequency is based on the assumptions in the analyses presented in Reference 2 and 4.

(continued)

BASES

TECHNICAL REQUIREMENTS SURVEILLANCE (continued)

TRS 13.3.33.3

This TRS has been deleted.

TRS 13.3.33.4

This TRS requires disassembly and inspection of at least one HP Stop Valve and one HP Control Valve on a 40 month Frequency to satisfy the turbine inservice inspection requirements described in Reference 6.

TRS 13.3.33.5

This TRS requires inspection of at least one LP Stop Valve and one LP Control Valve on a 40 month Frequency to satisfy the turbine inservice inspection requirements described in Reference 6.

TRS 13.3.33.6

This TRS requires a test of the Hardware Overspeed Sub-system 2 of 3 relay logic and output relays to ensure that this equipment is capable of processing an overspeed turbine trip signal on demand.

This equipment cannot be tested with the unit at power because performance of the test will trip the turbine. The 18 month test Frequency is consistent with Technical Specification test Frequencies assigned to similar equipment, and it affords the opportunity to test the equipment while the unit is shutdown. This test Frequency is judged to be acceptable based on the reliability of the equipment.

REFERENCES:

1. CPSES FSAR, Section 10.2.2.7.

2. CPSES FSAR, Section 3.5.1.3.

3. Engineering Report No. ER-504, Probability of Turbine Missiles from 1800 R/MIN Nuclear Steam Turbine-Generators with 46 -Inch Last Stage Turbine Blades, Allis-Chalmers (Siemens) Power Systems, Inc, October 1975 [VL-04-001540].

4. Supplement to ER-504, Comparison MTBF Evaluation Comanche Peak ST Protection and Trip System and Engineering Report No. ER-504 Probability of Turbine Missiles, Siemens Power Corporation, February 11, 2004 [VL-05-000489].

(continued)

BASES

REFERENCES: (continued)

5. CT-27331, Revision 4, Missile Probability Analysis Methodology for TXU Generation Company LP, Comanche Peak Units 1 and 2 with Siemens Retrofit Turbines, Siemens Westinghouse Power Corporation, October 29, 2004 [VL-05-001268].

6. CPSES FSAR, Section 10.2.3.6.

7. 59EV-2004-000774-01 and 59EV-2004-000774-02, 10CFR50.59 Evaluations for installation of the Turbine Generator Digital Protection System in Comanche Peak Unit 1 and Unit 2, respectively.

B 13.3 INSTRUMENTATION

TRB 13.3.34 Plant Calorimetric Measurement

BASES

BACKGROUND

The predominant contribution to the secondary plant calorimetric measurement uncertainty is the uncertainty associated with the feedwater flow measurement. Traditionally, a differential pressure (ΔP) transmitter across a venturi in each main feedwater line has been used to provide the feedwater flow. However, the venturis are subject to corrosion or fouling and the uncertainty associated with the flow derived from the ΔP indication can be large and increases as the flow deviates from the “optimum” conditions for which the ΔP transmitter was calibrated.

More recently, leading edge flow meters (LEFMs) have been used to provide the feedwater flow input to the secondary plant calorimetric measurement. The uncertainty associated with the LEFM is relatively small and is independent of the actual feedwater flow.

Most of the original safety analyses supporting plant operation were performed at a maximum power level of 3411 MW_{th} plus an allowance for the secondary plant calorimetric measurement of 2% power. However, through use of LEFMs, the uncertainty associated with the secondary plant calorimetric can be shown to be less than 0.6%. Hence, it is possible to support operation at a higher power level while remaining within the original analyses.

The RATED THERMAL POWER is 3458 MW_{th} which represents an increase of 1.4% RTP from the originally licensed value of 3411 MW_{th}. The 1.4% uprate to 3458 MW_{th} for Unit 1 will be implemented during 1RFO9. This uprate is based on reduced uncertainties associated with the secondary plant calorimetric measurement that may be attained through the use of an improved LEFM supplied by Caldon, Inc.; i.e., the LEFM√. Many of the accident analyses are performed at 102% of 3411 MW_{th}, or 3479 MW_{th}, where the 2% RTP is an allowance for the uncertainty associated with the power calorimetric measurement. With the LEFM√, the power calorimetric measurement uncertainty is less than 0.6% RTP. Without performing new accident analyses, the LEFM√ can be used to allow the plant to be operated at a redefined 100% RTP of 3458 MW_{th}.

(continued)

BASES

BACKGROUND (continued)

However, this allowance is predicated on the availability of the LEFM√ for performance of the calorimetric measurement; when the LEFM√ is unavailable, the uncertainties associated with the feedwater venturi-based measurement (2% RTP) must be used to ensure compliance with the safety analysis value of the core power of 3479 MW_{th}.

Surveillance Requirement SR 3.3.1.2 requires the performance of a comparison of the results of the calorimetric heat balance calculation to Nuclear Instrumentation System (NIS) and N-16 Power Monitor channel output. SR 3.3.1.2 Note 1 requires that the NIS and N-16 Power Monitor channels be adjusted if the absolute difference is > 2% RTP.

SR 3.3.1.2 is required to be performed every 24 hours (daily). At that time, the NIS and N-16 power indications must be normalized to indicate within at least ± 2% RTP of the calorimetric measurement. The plant may then be run for the next 24 hour period, using these normalized NIS and N-16 power indications, such that the calorimetric power does not exceed 100% RTP. Although the calorimetric power indication may be monitored continuously for control of the unit power, the calorimetric power indication is not required to be consulted again until the daily calorimetric comparisons of the NIS and N-16 power indications are performed.

Upon implementation of uprates to 3458 MW_{th}, the following general guidance is provided for operation of CPSES Units 1 and 2:

a. When the LEFM√ is available, the plant should be operated in a manner consistent with the LEFM√-based calorimetric measurement and at 3458 MW_{th} (100% RTP).

b. If the LEFM√ is unavailable, the plant may be operated at 3458 MW_{th} (100% RTP) using the NIS and N-16 power indications until the next performance of SR 3.3.1.2 is due.

c. If the LEFM√-based calorimetric measurement is unavailable at the time SR 3.3.1.2 is due, the feedwater venturi-based calorimetric measurement should be used for the performance of SR 3.3.1.2. However, to maintain consistency with the uncertainty analyses, the maximum allowable power should be reduced to 3411 MW_{th}, or 98.6% RTP. Either the NIS and N-16 power indications or the feedwater venturi-based calorimetric power indications may be used to control the unit power.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	Each of the analyzed accidents are evaluated for the range of power levels over which the reactor is allowed to be operated. Typically, the analyses are most limiting when initiated from a higher power level. The original analyses were performed for a core power of 3411 MW_{th} plus an allowance for the secondary power calorimetric measurement of 2% RTP. In general, these same analyses are used to support the revised RATED THERMAL POWER definition of a core power of 3458 MW_{th}. With the application of a 0.6% RTP uncertainty (based on the use of the LEFM√ feedwater flow input into the secondary plant calorimetric measurement), the analyses are evaluated at a power level of 3479 MW_{th}. Analyses that use statistical methods, such as the analysis of the dropped RCCA event, are explicitly evaluated for operation at 3411 MW_{th} with a 2% RTP uncertainty allowance and for operation at 3458 MW_{th} with a 0.6% RTP uncertainty allowance. The setpoints for those functions of the Reactor Protection System that are based on a percentage of power (i.e., the NIS, overpower N-16 and overtemperature N-16 trip functions) have been calculated based on analytical margins available at the 3458 MW_{th} definition of 100% RTP. Operation at 3411 MW_{th} does not require these setpoints to be adjusted.
LCO	The LCO requires the LEFM√ to be used for the completion of the daily secondary plant calorimetric measurement required in SR 3.3.1.2. The use of the LEFM√ ensures that the basis for operation at the RATED THERMAL POWER of 3458 MW_{th} is maintained.
APPLICABILITY	The requirement to use the LEFM√ for the performance of the secondary plant calorimetric measurement required by SR 3.3.1.2 is applicable to Unit 2 and to Unit 1 upon implementation of the uprate to 3458 MW_{th} during 1RFO9.

(continued)

BASES (continued)

ACTIONS

A.1

If the LEFM becomes unavailable during the intervals between performance of SR 3.3.1.2, plant operation may continue using the power indications from the NIS and N-16 systems. However, in order to remain in compliance with the bases for operation at a RATED THERMAL POWER of 3458 MW_{th}, the LEFM must be returned to service prior to performance of SR 3.3.1.2.

B.1, B.2, and B.3

If the Required Action or Completion Time of Condition A is not met (i.e., the LEFM has not been returned to service prior to the performance of SR 3.3.1.2), Condition B is entered. Required Action B.1 requires that the reactor power be reduced to, or maintained at, a power level less than or equal to 98.6% RTP (3411 MW_{th}). This power reduction is performed prior to performing SR 3.3.1.2 in order to remain within the plant's design bases immediately upon performance of SR 3.3.1.2.

Required Action B.2 directs the performance of SR 3.3.1.2 using the feedwater venturi indications of feedwater flow. Once SR 3.3.1.2 is performed using the feedwater venturi indications of feedwater flow, the required power uncertainty is 2% RTP. In order to maintain compliance with the safety analyses, it is necessary to operate the plant at a maximum core thermal power of 3411 MW_{th}.

Required Action B.3 serves as a reminder that the core power is to be maintained at a value less than or equal to 3411 MW_{th} until the LEFM is returned to service and SR 3.3.1.2 has been performed using the LEFM indication of feedwater flow. Once SR 3.3.1.2 has been performed, then the plant can again be operated at 3458 MW_{th}.

TECHNICAL REQUIREMENTS SURVEILLANCE

TRS 13.3.34.1 requires that the availability of the LEFM be verified prior to its use for the performance of SR 3.3.1.2. The self-diagnostics features of the LEFM√ should be used for this surveillance. If the LEFM indications are in the normal or alert status it is considered operable.

REFERENCES

1. License Amendment Request 01-005, Increase the licensed power for operation of CPSES Units 1 and 2 to 3458 MWth, Docket Nos. 50-445 and 50-446, CPSES.

B 13.4 REACTOR COOLANT SYSTEM

TRB 13.4.14 Reactor Coolant System (RCS) Pressure Isolation Valves

BASES

Related information is located in Technical Specification Bases 3.4.14.

B 13.4 REACTOR COOLANT SYSTEM

TRB 13.4.31 Loose Parts Detection System

BASES

The OPERABILITY of the Loose-Part Detection System ensures that sufficient capability is available to detect loose metallic parts in the Reactor System and avoid or mitigate damage to Reactor System components. The allowable out-of-service times and surveillance requirements are consistent with the recommendations of Regulatory Guide 1.133, “Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors,” May 1981.

B 13.4 REACTOR COOLANT SYSTEM

TRB 13.4.33 Reactor Coolant System (RCS) Chemistry

BASES

The limitations on Reactor Coolant System chemistry ensure that corrosion of the Reactor Coolant System is minimized and reduces the potential for Reactor Coolant System leakage or failure due to stress corrosion. Maintaining the chemistry within the Steady-State Limits provides adequate corrosion protection to ensure the structural integrity of the Reactor Coolant System over the life of the plant. The associated effects of exceeding the oxygen, chloride, and fluoride limits are time and temperature dependent. Corrosion studies show that operation may be continued with contaminant concentration levels in excess of the Steady-State Limits, up to the Transient Limits, for the specified limited time intervals without having a significant effect on the structural integrity of the Reactor Coolant System. The time interval permitting continued operation within the restrictions of the Transient Limits provides time for taking corrective actions to restore the contaminant concentrations to within the Steady-State Limits.

The Surveillance Requirements provide adequate assurance that concentrations in excess of the limits will be detected in sufficient time to take corrective action.

B 13.4 REACTOR COOLANT SYSTEM

TRB 13.4.34 Pressurizer

BASES

The temperature and pressure changes during heatup and cooldown are limited to be consistent with the requirements given in the ASME Boiler and Pressure Vessel Code, Section III, Appendix G and 10CFR50, Appendix G.

a. The pressurizer heatup and cooldown rates shall not exceed 100ºF/h and 200ºF/h, respectively.

b. System preservice hydrotests and in-service leak and hydrotests shall be performed at pressures in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section XI.

Although the pressurizer operates in temperature ranges above those for which there is reason for concern of nonductile failure, operating limits are provided to assure compatibility of operation with the fatigue analysis performed in accordance with the ASME Code requirements.

B 13.4 REACTOR COOLANT SYSTEM

TRB 13.4.35 Reactor Coolant System (RCS) Vents Specification

BASES

Reactor Coolant System vents are provided to exhaust noncondensible gases and/or steam from the Reactor Coolant System that could inhibit natural circulation core cooling. The OPERABILITY of at least one Reactor Coolant System vent path from the reactor vessel head, and the pressurizer steam space, ensures that the capability exists to perform this function.

The valve redundancy of the Reactor Coolant System vent paths serves to minimize the probability of inadvertent or irreversible actuation while ensuring that a single failure of a vent valve, power supply, or control system does not prevent isolation of the vent path.

The function, capabilities, and testing requirements of the Reactor Coolant System vents are consistent with the requirements of Item II.B.1 of NUREG-0737, “Clarification of TMI Action Plan Requirements,” November 1980.

B 13.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

TRB 13.5.31 ECCS - Containment Debris

BASES

Related information is located in Technical Specification Bases 3.5.2 and 3.5.3.

TRS 13.5.31.1 requires an inspection of accessible areas of containment to verify that no loose debris are present. For inspection purposes the definition of “Accessible areas” is clarified as follows. Areas which are physically restricted for the entire outage such as a bolted manway are considered “not accessible” for inspection purposes. Areas where access is restricted by a process control (e.g., RWP locked area) for the entire outage are considered “not accessible” for inspection purposes. It is the responsibility of the person(s) performing the close out inspections to verify whether or not the exception areas previously noted above have been accessed at any time during the outage.

Exception areas which have been accessed during the outage should have a close out debris inspection at the time access is once again restricted by either physical means or process controls. It is not necessary to re-inspect this exception area at the final close out inspection since an inspection was previously performed and access controlled.

B 13.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

TRB 13.5.31 ECCS - Pump Line Flow Rates

BASES

Related information is located in Technical Specification Bases 3.5.2 and 3.5.3.

B 13.6 CONTAINMENT SYSTEMS

TRB 13.6.3 Containment Isolation Valves

BASES

The OPERABILITY of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of General Design Criteria 54 through 57 of 10CFR50, Appendix A. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

AIRLOCK VALVES CREDITED AS CONTAINMENT ISOLATION VALVES

The following discussion is provided to clarify the bases for the application of TS LCO 3.6.2 to the airlock valves so designated in TRM Table 13.6.3-1 that are also credited as Containment Isolation Valves.

These airlock penetration isolation valves are located in penetrations that are required to be closed during accident conditions and are included in the TRM table of Containment Isolation Valves for completeness. These valves are manual valves secured in their closed position except when open under administrative controls as provided in the TRM.

The designated airlock valves, including the airlock test connection isolation valves, are part of the airlock leak tight boundaries and directly affect the requirements for Containment Air Lock OPERABILITY as defined by the TS Bases. Therefore, they are subject to the controls of Specification 3.6.2. As such, the requirements of Specification 3.6.3 do not apply.

Both Note 6 and the corresponding statements applicable to the airlock test connections included in the Table Notation for the local vent, drain, and test connections (TVDs), provide that the airlock valves are included in the table of Containment Isolation Valves for completeness and that the requirements of Specification 3.6.3 do not apply. Instead, the airlock valves are considered an integral part of the airlock and are therefore subject to the controls of Specification 3.6.2.

References:

1) Evaluation SE-90-222, approved 10/26/1990
2) Evaluation SE-91-104, approved 11/13/1991
   (Includes evaluation of “Tech Spec Applicability to Airlock Valves”)
3) LDCR TR-90-010, approved 11/20/1991
4) TUE Conference Memorandum TCO-91019, dated 6/10/1991
5) EVAL-2004-003317-01, re: LCO applicability to airlock boundary penetration valves

B 13.6 CONTAINMENT SYSTEMS

TRB 13.6.6 Containment Spray System

BASES

Related information is located in Technical Specification Bases 3.6.6.

B 13.7 PLANT SYSTEMS

TRB 13.7.31 Steam Generator Atmospheric Relief Valve (ARV) - Air Accumulator Tank

BASES

Related requirements/information is located in Technical Specification Bases Section 3.7.4.

B 13.7 PLANT SYSTEMS

TRB 13.7.32 Steam Generator Pressure / Temperature Limitation

BASES

The limitation on steam generator pressure and temperature ensures that the pressure-induced stresses in the steam generators do not exceed the maximum allowable fracture toughness stress limits. The limitations of 70ºF and 200 psig are based on a steam generator RTNDT of 60ºF and are sufficient to prevent brittle fracture. The pressure limit is applicable whenever the primary or secondary systems can be pressurized to the limit of 200 psig. For surveillance 13.7.32.1, the primary and secondary systems are considered no longer capable of being pressurized following depressurization to atmospheric conditions and when at least a 4 inch diameter vent path for the primary system and at least a 3 inch diameter vent path for the secondary system on the associated steam generator are established and administratively maintained (e.g., reactor vessel head removed for the primary system and all steam generator manways removed for the secondary system). If the primary and secondary vent path are being used to meet the LCO then surveillance 13.7.32.2 verifies the vent paths remain established.

B 13.7 PLANT SYSTEMS

TRB 13.7.33 Ultimate Heat Sink - Sediment and Safe Shutdown Impoundment (SSI) Dam

BASES

The limitations on the SSI Dam ensure that sufficient cooling capacity is available in the event of an SSE.

The limitation on average sediment depth is based on the possible excessive sediment buildup in the service water intake channel.

B 13.7 PLANT SYSTEMS

TRB 13.7.34 Flood Protection

BASES

The limitation of flood protection ensures that facility protective actions will be taken in the event of flood conditions. The only credible flood condition that endangers safety related equipment is from water entry into the turbine building via the circulating water system from Squaw Creek Reservoir and then only if the level is above 778 feet Mean Sea Level. This corresponds to the elevation at which water could enter the electrical and control building endangering the safety chilled water system. The surveillance requirements are designed to implement level monitoring of Squaw Creek Reservoir should it reach an abnormally high level above 776 feet. The Limiting Condition for Operation is designed to implement flood protection, by ensuring no open flow path via the Circulating Water System exists, prior to reaching the postulated flood level.

B 13.7 PLANT SYSTEMS

TRB 13.7.35 Snubbers

BASES

All snubbers are required OPERABLE to ensure that the structural integrity of the Reactor Coolant System and all other safety-related systems is maintained during and following a seismic or other event initiating dynamic loads.

Snubbers are classified and grouped by design and manufacturer but not by size. For example, mechanical snubbers utilizing the same design features of the 2-kip, 10-kip and 100-kip capacity manufactured by Company “A” are of the same type. The same design mechanical snubbers manufactured by Company “B” for the purposes of this Technical Specification would be of a different type, as would hydraulic snubbers from either manufacturer.

A list of individual snubbers with detailed information of snubber location and size and of system affected shall be available at the plant in accordance with 10CFR50.71(c). The accessibility of each snubber shall be determined and approved by the Station Operation Review Committee (SORC). The determination shall be based upon the existing radiation levels and the expected time to perform a visual inspection in each snubber location as well as other factors associated with accessibility during plant operations (e.g., temperature, atmosphere, location, etc.), and the recommendations of Regulatory Guides 8.8 and 8.10. The addition or deletion of any hydraulic or mechanical snubber shall be made in accordance with 10CFR50.59.

Surveillance to demonstrate OPERABILITY is by performance of the requirements of an approved inservice inspection program.

Permanent or other exemptions from the surveillance program for individual snubbers may be granted by the Commission if a justifiable basis for exemption is presented and, if applicable, snubber life destructive testing was performed to qualify the snubbers for the applicable design conditions at either the completion of their fabrication or at a subsequent date. Snubbers so exempted shall be listed in the list of individual snubbers indicating the extent of the exemptions.

The service life of a snubber is established via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (newly installed snubbers, seal replaced, spring replaced, in high radiation area, in high temperature area, etc.). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life.

B 13.7 PLANT SYSTEMS

TRB 13.7.36 Area Temperature Monitoring

BASES

The limitations on nominal area temperatures ensure that safety-related equipment will not be subjected to temperatures that would impact their environmental qualification temperatures. Exposure to temperatures in excess of the maximum temperature for normal conditions for extended periods of time could reduce the qualified life or design life of that equipment. Exposure to temperatures in excess of the maximum abnormal temperature could degrade the OPERABILITY of that equipment.

Normal and abnormal temperature limits for the following areas are assured by monitoring other areas with a correlated temperature relationship:

	TEMPERATURE LIMIT (°F)		
Area	Normal Conditions	Abnormal Conditions	Area Monitored
CRDM Platform Barrier	140	149	General Area CRDM Shroud Exhaust
Reactor Cavity Detector Well	135	175	Reactor Cavity Exhaust
R.C. Pipe Penetration Exhaust (N-16 Detectors)	200	209	General Areas Reactor Cavity Exhaust

B 13.7 PLANT SYSTEMS

TRB 13.7.37 Safety Chilled Water System - Electrical Switchgear Area Emergency Fan Coil Units

BASES

Related requirements/information is located in Technical Specification Bases Section 3.7.19.

Inoperable electrical switchgear area emergency fan coil units should not require actions more severe than the loss of the entire associated Safety Chilled Water System Train. Therefore, where one or more electrical switchgear area electrical fan coil units are inoperable it is acceptable to declare the associated Safety Chilled Water System Train inoperable and enter Technical Specifications 3.7.19.

B 13.7 PLANT SYSTEMS

TRB 13.7.38 Main Feedwater Isolation Valve Pressure / Temperature Limit

BASES

The fracture toughness requirements are satisfied with a metal temperature of 90°F for the main feedwater isolation valve body and neck, therefore, these portions will be maintained at or above this temperature prior to pressurization of these valves above 675 psig. Minimum temperature limitations are imposed on the valve body and neck of main feedwater isolation valves HV-2134, HV-2135, HV-2136 and HV-2137. These valves do not need to be verified at or above 90°F when in MODES 4, 5, or 6 (except during special pressure testing) since T_{avg} < 350°F which corresponds to a pressure at the valves of 140-150 psig or less. The maximum pressurization during cold conditions (valve temperature < 90°F) should be limited to no more than 20% of the valve hydrostatic test pressure (3375 psig X 20% = 675 psig).

B 13.7 PLANT SYSTEMS

TRB 13.7.39 Tornado Missile Shields

BASES

The purpose of tornado missile shields is to protect equipment from tornado generated missiles, and given the fact that adequate warning is available for tornado conditions, it is not necessary to consider protected equipment inoperable solely due to its missile shield being removed. This TRM provides conservative pre-planned allowances for control of missile shields without further consideration of equipment OPERABILITY. Removal of missile shields not contained herein, or exceeding the bounds of these allowances require additional assessment of equipment OPERABILITY. The conservative option to declare affected equipment inoperable and comply with the provisions of Technical Specifications is always available.

The following allowances have considered the impact on HVAC pressure boundaries, but do not address Security and Fire Protection requirements.

The capability to immediately re-install missile shields as used in the TRM allowances is deemed to exist when the necessary equipment to perform the installation is located on site and is available for use. Personnel necessary to operate the equipment shall be onsite and available when weather conditions exist such that a potential for a Tornado Watch or Warning exists. If weather conditions pose no immediate potential for adverse weather, then personnel associated with the operation of the equipment shall be available and within 90 minutes of the site. The shield shall also be in such condition and location to support reinstallation.

Removal and installation of missile shields shall be conducted in accordance with approved plant procedures.

Installation of each removed shield shall begin immediately upon the associated notification (Tornado Watch, Tornado Warning, etc.) otherwise the affected system(s) shall be declared inoperable.

(continued)

BASES

DEFINITIONS*:

1. Primary Plant Ventilation Pressure Boundary - An established physical boundary, within the confines of the Fuel, Auxiliary and Safeguards buildings, which has been demonstrated via surveillance testing to provide the negative pressure envelope required by LCO 3.7.12.

2. Direct Communication - The condition of having a known flow path, from the building through the Primary Plant Ventilation Pressure Boundary into the negative pressure envelope, that does not contain barriers which have been proven to adequately maintain the negative pressure envelope required by LCO 3.7.12.

* These definitions are used with the confines of this TRM specification only.

REFERENCE: TE-SE-90-615

B 13.7 PLANT SYSTEMS

TRB 13.7.41 Condensate Storage Tank (CST) Make-up and Reject Line Isolation Valves

BASES

BACKGROUND	The CST provides a safety grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS) to cool down the unit following all events in the accident analysis as discussed in the, FSAR Chapter 15. The CST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (TS 3.7.5). The CST also provides makeup and surge capacity for secondary system inventory changes caused by different operational conditions, thermal effects, and the draining and recharging of any part of the system. The CST is isolated from its non-safety-related users by automatically closing motor-operated valves in the make-up reject line when the motor-driven or turbine-driven auxiliary feedwater pumps start. The make-up and reject line tap is located above the safety related CST volume; therefore, closure is not a required safety function to prevent the outflow of CST water. The active safety function of the valves in the make-up and reject line is to prevent inflow which could adversely affect CST and AFW operability. The condensate make-up and reject line is also isolated by automatically closing motor operated valves HV-2484 and HV-2485 when the condensate storage tank reaches a HI-HI level. Automatic closure of these isolation valves is required to protect the CST from overpressurization or damage to the floating diaphragm which could result from a condenser surge. Overpressure of the tank could lead to failure. Damage to the liner could lead to common mode failure of all AFW pumps. The valves can also be operated manually from local control board switches. A description of the CST is found in the FSAR Section 9.2.6.
APPLICABLE SAFETY ANALYSES	The CST provides cooling water to remove decay heat and to cool down the unit during normal operation and following design bases events as discussed in the safety analyses in FSAR Chapters 3, 5, 6, 7, 9 and 15. The CST make-up and reject line isolation valves ensure the availability of the cooling water supply by protecting the CST.

(continued)

BASES

LCO

The LCO requires that two CST make-up and reject line isolation valves be OPERABLE to ensure that the valves function to protect the CST.

APPLICABILITY

In MODES 1, 2, and 3, the CST make-up and reject line isolation valves are required to be OPERABLE except when the CST make-up and reject line is isolated by a closed and de-activated isolation valve. When the CST make-up and reject line is isolated by a closed and de-activated isolation valve the safety function to protect the CST from overpressurization is already being met.

ACTIONS

A.1 and A.2

With one of the required make-up and reject line isolation valves inoperable in MODE 1, 2, or 3, except when the CST make-up and reject line is isolated by a closed and de-activated isolation valve, action must be taken to restore the valve to OPERABLE status or to isolate the make-up and reject flowpath within 72 hours and to verify the flowpath isolated every 31 days. The 72 hour Completion Time and 31 day surveillance interval are reasonable, based on capabilities afforded by the design with a redundant valve, time needed for repairs, and the low probability of a condenser surge occurring during this time period.

B.1

With both of the required make-up and reject line isolation valves inoperable in MODE 1, 2, or 3, except when the CST make-up and reject line is isolated by a closed and de-activated isolation valve, action must be taken to restore a make-up and reject line isolation valve to OPERABLE status within 4 hours or to isolate the make-up and reject flowpath. The 4 hour completion time is reasonable given the low probability of a condenser surge occurring during this time period.

C.1 and C.2

With the completion time of Condition A or B not met, a backup water supply must be determined to be available by administrative means within 4 hours and once every 12 hours thereafter. OPERABILITY of the backup water supply must include verification that the flow paths from the backup water supply to the AFW pumps are OPERABLE, and that the SSWS is Operable. In addition, each motor operated valve between the SSWS and each Operable AFW pump must be OPERABLE. If isolation of the makeup and reject line is not possible then both make-up and

(continued)

BASES

ACTIONS (continued)	C.1 and C.2 (continued) reject line isolation valves must be restored to OPERABLE status within 7 days, because the backup supply is not automatic. The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the backup water supply. Additionally, verifying the backup water supply every 12 hours is adequate to ensure the backup water supply continues to be available. The 7 day Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the CST.
TECHNICAL REQUIREMENTS SURVEILLANCE	TRS 13.7.41.1 The surveillance requirement verifies the operability of the make-up and reject line valves and their actuation circuitry on an actual or simulated HI-HI CST level signal or an SI signal to ensure the protection of the CST and floating diaphragm from overpressurization. TRS 13.7.41.2 The surveillance requirement verifies that a make-up and reject line isolation actuation signal is initiated on CST HI-HI level.

B 13.8 ELECTRICAL POWER SYSTEMS

TRB 13.8.31 AC Sources (Diesel Generator Requirements)

BASES

Related requirements/information is located in Technical Specification Bases Section 3.8.1.

These surveillance requirements reflect normal design, maintenance or line-up activities/ descriptions rather than features specifically needed to successfully mitigate a DBA or design transient.

The diesel’s preventative maintenance program is commensurate for nuclear standby service, which takes into consideration the following factors: manufacturer’s recommendations, diesel owners group’s recommendations, engine run time, equipment performance, calendar time, and plant preventative maintenance programs.

B 13.8 ELECTRICAL POWER SYSTEMS

TRB 13.8.32 Containment Penetration Conductor Overcurrent Protection Devices

BASES

Containment electrical penetrations and penetration conductors are protected by either deenergizing circuits not required during reactor operation or by demonstrating the OPERABILITY of primary and backup overcurrent protection circuit breakers during periodic surveillance. This is based on the recommendations of Regulatory Guide 1.63, Revision 2, July 1978, “Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants.”

The Surveillance Requirements applicable to lower voltage circuit breakers provide assurance of breaker reliability by testing at least 10% of each manufacturer's brand of circuit breaker. Each manufacturer's molded case and metal case circuit breakers are grouped into representative samples which are then tested on a rotating basis to ensure that all breakers are tested. If a wide variety exists within any manufacturer's brand of circuit breakers, it is necessary to divide that manufacturer's breakers into groups and treat each group as a separate type of breaker for surveillance purposes.

All Class 1E motor-operated valves' motor starters are provided with thermal overload protection which is permanently bypassed and provides an alarm function only at Comanche Peak Steam Electric Station. Therefore, there are no OPERABILITY or Surveillance Requirements for these devices, since they will not prevent safety-related valves from performing their function (refer to Regulatory Guide 1.106, “Thermal Overload Protection for Electric Motors on Motor Operated Valves,” Revision 1, March 1977).

B 13.9 REFUELING OPERATIONS

TRB 13.9.31 Decay Time

BASES

The minimum requirement for reactor subcriticality prior to movement of irradiated fuel assemblies in the reactor vessel ensures that sufficient time has elapsed to allow the radioactive decay of the short-lived fission products. This decay time is consistent with the assumptions used in the safety analyses.

B 13.9 REFUELING OPERATIONS

TRB 13.9.32 Refueling Operations / Communications

BASES

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity conditions during CORE ALTERATIONS.

B 13.9 REFUELING OPERATIONS

TRB 13.9.33 Refueling Machine

BASES

The OPERABILITY requirements for the refueling machine main hoist and auxiliary monorail hoist ensure that: (1) the main hoist will be used for movement of fuel assemblies, (2) the auxiliary monorail hoist will be used for latching, unlatching and movement of control rod drive shafts, (3) the main hoist has sufficient load capacity to lift a fuel assembly (with control rods), (4) the auxiliary monorail hoist has sufficient load capacity to latch, unlatch and move the control rod drive shafts, and (5) the core internals and reactor vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations.

B 13.9 REFUELING OPERATIONS

TRB 13.9.34 Refueling - Crane Travel - Spent Fuel Storage Areas

BASES

The restriction on movement of loads in excess of the nominal weight of a fuel and control rod assembly and associated handling tool over other fuel assemblies in a storage pool ensures that in the event this load is dropped: (1) the activity release will be limited to that contained in a single fuel assembly, and (2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

B 13.9 REFUELING OPERATIONS

TRB 13.9.35 Water Level, Reactor Vessel, Control Rods

BASES

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. The minimum water depth is consistent with the assumptions of the safety analysis.

B 13.9 REFUELING OPERATIONS

TRB 13.9.36 Fuel Storage Area Water Level

BASES

The requirement to suspend crane operations over the spent fuel pool in the event pool water level is < 23 feet provides for conservative plant operations consistent with the accident analysis. The bounding design basis fuel handling accident in the spent fuel pool assumes 23 feet of water above the damaged fuel assembly in the spent fuel pool which mitigates the radiological consequences.

Crane operations that could adversely affect fuel stored in the spent fuel pool are controlled in accordance with plant procedures as analyzed in the review of heavy loads movements. Administrative controls are employed to prevent the handling of loads that have a greater potential energy than those which have been analyzed. This Technical Requirement further ensures, for loads < 2150 pounds, that the water level is greater than that assumed in the analysis.

REFERENCE: NRC Bulletin 96-02, "Movement of Heavy Loads Over Spent Fuel, Over Fuel in the Reactor Core, or Over Safety-Related Equipment."

B 13.10 EXPLOSIVE GAS AND STORAGE TANK RADIOACTIVITY MONITORING PROGRAM

TRB 13.10.31 Explosive Gas Monitoring Instrumentation

BASES

The explosive gas instrumentation is provided to monitor and control, the concentrations of potentially explosive gas mixtures in the WASTE GAS HOLDUP SYSTEM. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 63, and 64 of 10 CFR 50, Appendix A.

One hydrogen and two oxygen monitors are required to be OPERABLE for the operating recombiner during WASTE GAS HOLDUP SYSTEM (WGHS) operation. The following discussion provides clarification of “WGHS operation” and “degassing”.

For the purpose of this specification, with no input gases allowed to the WGHS, recirculation of the WGHS as well as sampling, recirculation, storage, and discharge of a waste gas decay tank are not considered as WGHS operation.

Degassing operation (which is a type of WGHS operation) is defined as purging the RCS of residual gases during unit shutdown.

B 13.10 EXPLOSIVE GAS AND STORAGE TANK RADIOACTIVITY MONITORING PROGRAM

TRB 13.10.32 Gas Storage Tanks

BASES

The tanks included in this specification are those tanks for which the quantity of radioactivity contained is not limited directly or indirectly by another Technical Specification. Restricting the quantity of radioactivity contained in each gas storage tank provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting whole body exposure to a MEMBER OF THE PUBLIC at the nearest SITE BOUNDARY will not exceed 0.5 rem. This is consistent with Standard Review Plan 11.3, Branch Technical Position ETSB 11-5, “Postulated Radioactive Releases Due to a Waste Gas System Leak or Failure,” in NUREG-0800, July 1981.

B 13.10 EXPLOSIVE GAS AND STORAGE TANK RADIOACTIVITY MONITORING PROGRAM

TRB 13.10.33 Liquid Holdup Tanks

BASES

The tanks listed in this specification include all those unprotected outdoor tanks both permanent and temporary that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting concentrations would be less than the values given in Appendix B, Table 2, Column 2, to 10 CFR 20.1001 - 20.2402, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

B 13.10 EXPLOSIVE GAS AND STORAGE TANK RADIOACTIVITY MONITORING PROGRAM

TRB 13.10.34 Explosive Gas Mixture

BASES

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the WASTE GAS HOLDUP SYSTEM is maintained below the flammability limits of hydrogen and oxygen. Automatic control features are included in the system to prevent the hydrogen and oxygen concentrations from reaching these flammability limits. These automatic control features include isolation of the source of hydrogen and/or oxygen. Maintaining the concentration of hydrogen and oxygen below their flammability limits provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of 10CFR50 Appendix A.

COMANCHE PEAK STEAM ELECTRIC STATION UNITS 1 & 2
TECHNICAL REQUIREMENTS MANUAL (TRM)

EFFECTIVE LISTING FOR SECTIONS

Revision Record:

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Revision 3	July 20, 1990
Revision 4	April 24, 1991
Revision 5	September 6, 1991
Revision 6	November 22, 1991
Revision 7	March 18, 1992
Revision 8	June 30, 1992
Revision 9	December 18, 1992
Revision 10	January 22, 1993
Revision 11	February 3, 1993
Revision 12	July 15, 1993
Revision 13	September 14, 1993
Revision 14	November 30, 1993
Revision 15	April 15, 1994
Revision 16	May 11, 1994
Revision 17	February 24, 1995
Revision 18	April 14, 1995
Revision 19	May 15, 1995
Revision 20	June 30, 1995
Revision 21	January 24, 1996
Revision 22	February 24, 1997
Revision 23	March 13, 1997
Revision 24	June 26, 1997
Revision 25	July 31, 1997
Revision 26	February 24, 1998
Revision 27	April 14, 1999
Revision 28	April 16, 1999
Revision 29	July 27, 1999
Revision 30	July 27, 1999
Revision 31	August 5, 1999
Revision 32	September 24, 1999
Revision 33	October 7, 1999
Revision 34	June 29, 2000
Revision 35	September 30, 2000
Revision 36	May 30, 2001
Revision 37	August 14, 2001
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COMANCHE PEAK STEAM ELECTRIC STATION UNITS 1 & 2
TECHNICAL REQUIREMENTS MANUAL (TRM)

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Revision 57	July 27, 2006
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COMANCHE PEAK STEAM ELECTRIC STATION UNITS 1 & 2
TECHNICAL REQUIREMENTS MANUAL (TRM)

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Section 13.0	Revision 56
Section 13.1	Revision 56
Section 13.2	Revision 56
Section 13.3	Revision 61
Section 13.4	Revision 56
Section 13.5	Revision 56
Section 13.6	Revision 56
Section 13.7	Revision 60
Section 13.8	Revision 59
Section 13.9	Revision 56
Section 13.10	Revision 56
Section 15.5	Revision 56

COMANCHE PEAK STEAM ELECTRIC STATION UNITS 1 & 2
TECHNICAL REQUIREMENTS MANUAL (TRM)

EFFECTIVE LISTING FOR SECTIONS

Section B 13.0	Revision 56
Section B 13.1	Revision 56
Section B 13.2	Revision 56
Section B 13.3	Revision 61
Section B 13.4	Revision 56
Section B 13.5	Revision 56
Section B 13.6	Revision 56
Section B 13.7	Revision 56
Section B 13.8	Revision 58
Section B 13.9	Revision 56
Section B 13.10	Revision 56
EL-1	Revision 61
EL-2	Revision 61
EL-3	Revision 61
EL-4	Revision 61

REVISION 56

LDCR-TR-2006-7 (EVAL-2005-005086-12) (TJE):

Administrative change for software conversion only.

The type of changes include changes such as (1) correction of spelling errors, (2) correction of inadvertent word processing errors from previous changes, and (3) style guide changes (e.g., changing from a numbered bullet list to an alphabetized bullet list and vice versa, change numbering of footnote naming scheme).

The entire TRM and TRM Bases will be reissued as Revision 56. For the text and tables there will be no change bars in the page margins for the editorial changes.

The list of effective pages is being replaced with a list of effective sections, tables, and figures.

Sections Revised: All

Tables Revised: All

Figures Revised: All

REVISION 57

LDCR-TR-2006-9 (EVAL-2004-000501-1) (TJE):

Correct tag number in Table 13.8.32-1b section 3.1 MCC 2EB1-2 compartment number 12B from "Personnel Air Lock Hydraulic Unit #2" to "Personnel Air Lock Hydraulic Unit #2 (CP2-BSAPPA-02M)"

1.) In Table 13.8.32-1b, the last sectence in section 4.3 description, replace the existing words,

"These breakers are Square D type FC, KH, and LH." with the words,

"These breakers are Square D type FH, KH, FA, and LH."

2.) Correct typos in tag numbers in Table 13.8.32-1b section 4.3.a,

a.) Devise Location Ckt 2, change Breaker Type from FC to FH

b.) Device Location Ckt 1 / Bkr-1, under System Powered, by removing the "-" between CP and 2 in two places.

3.) Corrects tag number in Table 13.8.32-1b section 4.3.b

a.) Devise Location Ckt 4, "Personnel Airlock Hydraulic Units CP-2-MEMEHU-01 and 02" to "Personnel Airlock Hydraulic Unit #2 (CP2-BSAPPA-02M)"

REVISION 57 (continued)

LDCR-TR-2006-9 (EVAL-2004-000501-1) (TJE) (continued):

b.) Devise Location Ckt 6, change Breaker Type from F4 to FH

Correct typo to remove a dash in Table 13.7.39-1, Shield tag number from, "Removable Slab (Hatch Cover) SW Pump, CP-1-SWAPSW-02" to "Removable Slab (Hatch Cover) SW Pump, CP1-SWAPSW-02"

REVISION 58

LDCR-TR-2006-3 (EVAL-2005-004275-02) (TJE):

1.) Currently, TRS 13.8.31.2 reads, "Subject the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacture"s recommendations for this class of standby service." The LDCR proposes to revise the TRS 13.8.31.2 to read, "Subject the diesel to inspections in accordance with procedures prepared in conjunction with the diesel owners group's preventive maintenance program."

NOTE:

The revision of this SR is proposed due to changes in the PM program recommended by the Cooper Owners Group which the CPSES EDGs are included in. The PM program is not being deleted nor are the vendor's recommendations being ignored. The current PM program is being enhanced to include vendor input, predictive maintenance input, performance based input and the Cooper Owners Group input. The program changes will provide the site with the opportunity to move from a prescriptive time based program to a risk informed performance based program.

At the end of this section, add the words, "The diesel's preventative maintenance program is commensurate for nuclear standby service, which takes into consideration the following factors: manufacturer's recommendations, diesel owners group's recommendations, engine run time, equipment performance, calendar time, and plant preventative maintenance programs."

NOTE:

The revision of this SR is proposed due to changes in the PM program recommended by the Cooper Owners Group which the CPSES EDGs are included in. The PM program is not being deleted nor are the vendor's recommendations being ignored. The current PM program is being enhanced to include vendor input, predictive maintenance input, performance based input and the Cooper Owners Group input. The program changes will provide the site with the opportunity to move from a prescriptive time based program to a risk informed performance based program.

REVISION 59

LDCR-TR-2004-5 (EVAL-2004-001881-04) (TJE):

Circuit Breaker 1ED1-1/14/BKR will be deleted from Table 13.8.32-1a under number 6.b. Backup Breakers.

LDCR-TR-2005-10 (EVAL-2004-000773-05) (RAS):

Revise TR LCO 13.3.33 from "At least one Turbine Overspeed Protection System shall be OPERABLE" to "At least one Turbine Overspeed Protection Sub-system shall be OPERABLE"

Revise Condition C from " Turbine overspeed protection inoperable for reasons other than Condition A or B" to Both Overspeed Protection Sub-systems inoperable"

Revise TRS 13.3.33.1 to replace the Unit specific surveillance statements with the following statement applicable equally to both Units:

"Test the Turbine Trip Block using the Automatic Turbine Tester (ATT)."

Delete TRS 13.3.33.3 and its associated frequency.

Revise TRS 13.3.33.6 as follows to make it applicable to both Units:

"Test the Hardware Overspeed Sub-system 2 of 3 relay logic and output relays"

Delete the existing TRM Bases description and replace in its entirety with the following:

BACKGROUND

This specification is provided to ensure that the turbine overspeed protection instrumentation and the turbine Stop and Control Valves are operable and will protect the turbine from excessive overspeed. Protection from excessive overspeed is necessary to prevent the generation of potentially damaging missiles which could impact and damage safety-related components, equipment and structures. Turbine overspeed is limited by rapid closure of the turbine Stop or Control Valves whenever turbine power exceeds generator output, as would exist immediately following a load rejection.

The Electrohydraulic Control (EHC) System is the primary means of limiting the extent of an overspeed event, with the turbine Overspeed Protection System as a backup. The EHC System is designed to limit transient overspeed to less than 110% of rated speed after a full load rejection by closing both the High Pressure (HP) and Low Pressure (LP) Control Valves. This function of the EHC System is performed by the normal speed/load control logic in conjunction with additional protection logic that ensures closure of all control valves under certain load rejection scenarios (Reference 1).

REVISION 59 (continued)

To minimize the possibility of a component failure resulting in a loss of the control function, the EHC System utilizes triple redundant speed and load inputs, dual redundant digital controller processors, and dual redundant outputs (amplifiers, proportional valves, and follow-up piston banks) to the Control Valves.

In the unlikely event that the EHC System fails to limit the overspeed condition, the Overspeed Protection System will act to limit the overspeed to less than 120% of rated speed.

The Overspeed Protection System is made up of the following basic component groups:

Independent and redundant speed sensors and associated signal processing instrumentation, including bistables, provide individual speed channel trip signals to the Turbine AG-95F Digital Protection System and the hardware overspeed trip system (both described below) whenever turbine speed exceeds 1980 rpm.

The Turbine AG-95F Digital Protection System consists of three independent and redundant trains of equipment, including input modules, dual redundant automation processors and associated software, output modules, and output relays. The AG-95F System is a fail-safe system in that all inputs and outputs are normally energized in the non-tripped state.

Each train of the AG-95F System processes the individual speed channel trip signals using 2 of 3 trip logic. When the trip logic is satisfied, the associated output relays de-energize, each one subsequently de-energizing its associated Turbine Trip Block solenoid valve.

The Relay Protection System consists of relay logic and output relays that are diverse from, and completely bypass, the AG-95F Digital Protection System described above. The logic and output relays are normally energized in the non-tripped state.

The relay logic processes the individual speed channel trip signals using 2 of 3 trip logic. When the trip logic is satisfied, all three output relays de-energize, each one subsequently de-energizing its associated Turbine Trip Block solenoid valve.

The Turbine Trip Block utilizes three independent and redundant solenoid valves to actuate associated hydraulic pistons that are configured in a manner that provides a hydraulic 2 of 3 trip logic. When any two of the three solenoid valves de-energize, actuation of the associated pistons rapidly de-pressurizes the turbine Trip Fluid System, causing all turbine Stop and Control Valves to close. De-energization of a single solenoid valve will not trip the turbine.

The Overspeed Protection System consists of two redundant and diverse sub-systems, the Hardware Overspeed Sub-system and the Software Overspeed Sub-system, that are configured using the component groups described above. Either of these sub-systems can independently trip the turbine.

REVISION 59 (continued)

The Hardware Overspeed Sub-system utilizes a set of three dedicated speed channels, each of which provides a trip signal to the Relay Protection System. Upon receipt of trip signals from any two of these speed channels, the relay logic de-energizes all three output relays which subsequently de-energize all three Turbine Trip Block solenoid valves, causing the turbine to trip.

As a backup, the three dedicated Hardware Overspeed Sub-system speed channels also provide trip signals to all three of the AG-95F System protection trains. Upon receipt of trip signals from any two of these speed channels, the output relay of each protection train is de-energized, subsequently de-energizing all three Turbine Trip Block solenoid valves, causing the turbine to trip.

The Software Overspeed Sub-system utilizes a second set of three dedicated speed channels which provide input to all three of AG-95F System protection trains. Upon receipt of trip signals from any two of these speed channels, the output relay of each protection train is de-energized, subsequently de-energizing all three Turbine Trip Block solenoid valves, causing the turbine to trip. The Software Overspeed System speed channels also provide speed signals to the EHC System as described above.

The design of the Overspeed Protection System includes several testing features that are used to ensure OPERABILITY of the system. These features include three Automatic Turbine Tester (ATT) tests that are manually initiated by the operator. They also include a test that is automatically executed by the system to ensure OPERABILITY of the speed channel instrumentation.

The ATT HP and LP Valve Tests cycle all Stop and Control Valves to ensure reliability and continuity of service. The HP and LP Stop Valve closure times are also verified to be within required response times (500 and 1500 msec, respectively). These tests cycle one pair of Stop and Control Valves at a time, so they may be performed with the plant on-line below approximately 85% power.

The ATT Turbine Trip Block Test de-energizes each Turbine Trip Block solenoid valve and verifies that the associated hydraulic piston moves to the trip position. The solenoid valve/piston pairs are sequentially tested one at a time, until all three are tested. Each pair is reset prior to testing the subsequent pair. Since only one solenoid valve/piston pair is tested at a time, the Trip Fluid System is never de-pressurized, and the turbine does not trip.

Each of the six individual speed channels (three for the Hardware Overspeed Sub-system and three for the Software Overspeed Sub-system), is automatically tested once every 24 hours when turbine speed is >40 rpm. These tests verify that the speed channels trip when speed is simulated above 1980 rpm. The tests are initiated by the AG-95F System in a manner that precludes two speed channels from being tested at the same time. If desired, the speed channel tests may also be initiated by the operator.

Alarms are provided to alert the operator in the event a fault/failure is detected during the execution of any of the aforementioned tests.

REVISION 59 (continued)

APPLICABLE SAFETY ANALYSIS

The Overspeed Protection System is required to be OPERABLE to provide sufficient protection against generation of potentially damaging missiles which could impact and damage safety-related components, equipment and structures. The turbine missile analysis is presented in Reference 2. Using References 3 through 5 as a basis, this analysis concludes that the risk for loss of an essential system due to a turbine missile event is acceptably low.

The robust design of the Overspeed Protection System, with its multiple speed channels, diverse hardware and software logic, and multiple Turbine Trip Block solenoid valves/ hydraulic pistons, meets the intent of SRP 10.2 Part III for redundancy and independence.

LCO

The Turbine Overspeed Protection Sub-systems are the Hardware Overspeed Sub-system and the Software Overspeed Sub-system, one of which shall be OPERABLE.

The robust design of these sub-systems allows for the failure of individual components without rendering the sub-system(s) inoperable. Specifically, the minimum operability requirements for the Hardware Overspeed Sub-system include:

two OPERABLE dedicated hardware speed channels, and OPERABLE hardware relay logic with two OPERABLE output relays and associated Turbine Trip Block solenoid valves/hydraulic pistons

OR

two OPERABLE dedicated hardware speed channels and two OPERABLE AG-95F System trains, including output relays and associated Turbine Trip Block solenoid valves/ hydraulic pistons

The minimum operability requirements for the Software Overspeed Sub-system include:

two OPERABLE dedicated software speed channels and two OPERABLE AG-95F System trains, including output relays and associated Turbine Trip Block solenoid valves/ hydraulic pistons

Individual component failures that do not render the sub-system(s) inoperable are addressed under the Corrective Action Program (CAP) with restoration times commensurate with the severity of the failure and the operational impact associated with the rework or repair.

Furthermore, component failures that result in rendering only one Overspeed Protection Sub-system inoperable are also addressed under the CAP with restoration times commensurate with the severity of the failure and the operational impact associated with the rework or repair.

REVISION 59 (continued)

APPLICABILITY

The OPERABILITY of one Overspeed Protection Sub-system ensures that the Overspeed Protection System is available to prevent an overspeed event while the unit is operating in MODE 1, 2, and 3 with steam available to roll the turbine. The APPLICABILITY is modified by a Note specifying that Overspeed Protection Sub-system OPERABILITY is not required in MODE 2 and 3 if the turbine is isolated from the steam supply by closing all Main Steam Isolation Valves and associated bypass valves.

ACTIONS

A.1, A.2, and A.3

This ACTION is modified by a Note that specifies that separate Condition entries are allowed for each steam line if valves are inoperable in multiple steam lines.

If an HP Stop or Control Valve is inoperable such that it is not capable of properly isolating the steam line to the turbine in response to an overspeed event, action must be taken to restore the valve(s) to OPERABLE status. Failure to restore the valve(s) to OPERABLE status within 72 hours requires that compensatory action be taken within the following 6 hours to ensure that the affected steam line is isolated by other means.

The 72 hour Completion Time for restoring the valve(s) takes into account the OPERABILITY of the remaining valve in the affected steam line and reasonable time for rework or repair. The 6 hour compensatory action Completion Time is reasonable, based on operating experience, for reaching the required unit conditions from full power operation in an orderly manner and without challenging unit systems.

B.1, B.2, and B.3

This ACTION is modified by a Note that specifies that separate Condition entries are allowed for each steam line if valves are inoperable in multiple steam lines.

If an LP Stop or Control Valve is inoperable such that it is not capable of properly isolating the steam line to the turbine in response to an overspeed event, action must be taken to restore the valve(s) to OPERABLE status. Failure to restore the valve(s) to OPERABLE status within 72 hours requires that compensatory action be taken within the following 6 hours to ensure that the affected steam line is isolated by other means.

The 72 hour Completion Time for restoring the valve(s) takes into account the OPERABILITY of the remaining valve in the affected steam line and reasonable time for rework or repair. The 6 hour compensatory action Completion Time is reasonable, based on operating experience, for reaching the required unit conditions from full power operation in an orderly manner and without challenging unit systems.

REVISION 59 (continued)

C.1

If both Overspeed Protection Sub-systems are inoperable, such that neither is capable of initiating a turbine trip in response to an overspeed event, action must be taken within 6 hours to isolate the turbine from the steam supply.

The 6 hour Completion Time for isolating the turbine from the steam supply is reasonable, based on operating experience, for reaching the required unit conditions from full power operation in an orderly manner and without challenging unit systems.

D.1, D.2, and D.3

In the event that the aforementioned ACTIONS and associated Completion Times cannot be satisfied, action must be initiated within 1 hour to place the unit in a lower MODE, with subsequent action to place the unit in MODE 3 within the following 6 hours and to place the unit in MODE 4 within 6 hours after entering MODE 3. The need to perform these actions would most likely result from the inability to isolate the turbine from the steam supply. Placing the unit in MODE 4 will reduce steam pressure to the point where there is insufficient motive force to overspeed the turbine, even if it is not isolated from the steam generators.

The Completion Times are reasonable, based on operating experience, for reaching MODE 3 and MODE 4 from full power operation in an orderly manner and without challenging unit systems.

TECHNICAL REQUIREMENTS SURVEILLANCE

The TRS 13.3.33 requirements are modified by a Note that specifies that the provisions of TRS 13.0.4 are not applicable.

TRS 13.3.33.1

This TRS specifies testing of the Turbine Trip Block using the Automatic Turbine Tester (ATT). This test de-energizes each Turbine Trip Block solenoid valve and verifies that the associated hydraulic piston moves to the trip position. The solenoid valve/piston pairs are sequentially tested one at a time, until all three are tested. Each pair is reset prior to testing the subsequent pair. Since only one solenoid valve/piston pair is tested at a time, the Trip Fluid System is never de-pressurized, and the turbine does not trip.

The 14 day test Frequency is based on the assumptions in the analyses presented in References 2 and 4.

REVISION 59 (continued)

TRS 13.3.33.2

This TRS specifies testing of the turbine HP and LP Stop and Control Valves using the ATT. These tests cycle all Stop and Control Valves to ensure reliability and continuity of service. The HP and LP Stop Valve closure times are also verified to be within required response times (500 and 1500 msec, respectively). These tests cycle one pair of Stop and Control Valves at a time, so they may be performed with the plant on-line below approximately 85% power.

The 12 week test Frequency is based on the assumptions in the analyses presented in References 2 and 4.

TRS 13.3.33.3

This TRS has been deleted.

TRS 13.3.33.4

This TRS requires disassembly and inspection of at least one HP Stop Valve and one HP Control Valve on a 40 month Frequency to satisfy the turbine inservice inspection requirements described in Reference 6.

TRS 13.3.33.5

This TRS requires inspection of at least one LP Stop Valve and one LP Control Valve on a 40 month Frequency to satisfy the turbine inservice inspection requirements described in Reference 6.

TRS 13.3.33.6

This TRS requires a test of the Hardware Overspeed Sub-system 2 of 3 relay logic and output relays to ensure that this equipment is capable of processing an overspeed turbine trip signal on demand.

This equipment cannot be tested with the unit at power because performance of the test will trip the turbine. The 18 month test Frequency is consistent with Technical Specification test Frequencies assigned to similar equipment, and it affords the opportunity to test the equipment while the unit is shutdown. This test Frequency is judged to be acceptable based on the reliability of the equipment.

REFERENCES

1. CPSES FSAR, Section 10.2.2.7

2. CPSES FSAR, Section 3.5.1.3

REVISION 59 (continued)

3. Engineering Report No. ER-504, Probability of Turbine Missiles from 1800 R/MIN Nuclear Steam Turbine-Generators with 46-Inch Last Stage Turbine Blades, Allis-Chalmers (Siemens) Power Systems, Inc, October 1975 [VL-04-001540]

4. Supplement to ER-504, Comparison MTBF Evaluation Comanche Peak ST Protection and Trip System and Engineering Report No. ER-504 Probability of Turbine Missiles, Siemens Power Corporation, February 11, 2004 [VL-05-000489]

5. CT-27331, Revision 4, Missile Probability Analysis Methodology for TXU Generation Company LP, Comanche Peak Units 1 and 2 with Siemens Retrofit Turbines, Siemens Westinghouse Power Corporation, October 29, 2004 [VL-05-001268]

6. CPSES FSAR, Section 10.2.3.6

7. 59EV-2004-000774-01 and 59EV-2004-000774-02, 10CFR50.59 Evaluations for installation of the Turbine Generator Digital Protection System in Comanche Peak Unit 1 and Unit 2, respectively

REVISION 60

LDCR-TR-2007-1 (EVAL-2004-001966-05) (TJE):

Change TRS 13.3.31.2 frequency to 24 months from 18 months.

LDCR-TR-2006-10 (EVAL-2006-002274-01) (CBC):

LDCR-TR-2006-010, EVAL-2006-002274-01: The Required Action and Completion Time for A.1.1 and A.1.2 of TRM 13.7.35, "Snubbers" are replaced with "Enter the operability determination process for attached system(s)." [Required Action] and "Immediately" [Completion Time]. Condition B and it's associated Required Action and Completion Time are deleted. TRM 13.7.35, "Snubbers" Condition A, Required Action A allows 72 hours for an inoperable snubber (to either be repaired or replaced) before the associated system/train is declared inoperable. Although this 72 hour provision was relocated from Technical Specifications during conversion to the Improved STS, the NRC has indicated that it is improper to allow an exception to the TS definition of Operability for this support system by way of the TRM. As a result, the industry and the NRC have developed a revision to the STS in TSTF-372. This TSTF is NRC approved and ready for adoption. The TSTF allows 72 hours (or 12 hours for a snubber affecting both trains) for seismic snubbers before declaring the system inoperable using a risk informed approach by the addition new TS 3.0.8. Since there are no current plans to adopt TSTF-372 at Comanche Peak, TRM 13.7.35 is revised to remove the 72 hour delay. Deletion of the 72 hour delay is consistent with the NRC's expectations as stated in 70FR23252.

REVISION 60 (continued)

TR LCO 13.7.35 is revised to exclude certain snubbers. Those snubber(s) that have an anlysis which determines that the supported TS sytem(s) do not require the snubber(s) to be functional in order to support the operability of the system(s) are excluded from TR LCO 13.7.35. This is consistent with Section 4.1 of TSTF-IG-05-03, IMPLEMENTATION GUIDANCE FOR TSTF-372, REVISION 4, "ADDITION OF LCO 3.0.8, INOPERABILITY OF SNUBBERS," dated Ocober 2005 and RIS-2005-020, REVISION TO GUIDANCE FORMERLY CONTAINED IN NRC GENERIC LETTER 91-18, INFORMATION TO LICENSEES REGARDING TWO NRC INSPECTION MANUAL SECTIONS ON RESOLUTION OF DEGRADED AND NONCONFORMING CONDITIONS AND ON OPERABILITY," dated September 26, 2005.

REVISION 61

LDCR-TR-2006-1 (EVAL-2004-001966-03) (TJE):

Justification: The use of the new Seismic Monitoring System with only free-field ground motion input will not compromise the ability of the system to determine whether or not the OBE was exceeded and subsequent shutdown of both units per Appendix A of 10CFR100. Therefore, the new Seismic Monitoring System does not present any added risk to public health or nuclear safety.

The deletion of the steps for restoring the seismic monitoring system to an operable status and for the interpretation of the seismic data reflects a change in technology provided with the new system. The previous seismic monitoring system was rendered inoperable during the process of recording a seismic event. With the exception of the three triaxial accelerometers, the previous system used smoked scribe plates in the sensors that can not distinguish between different seismic events. In order to interpret the data from a seismic event and restore operability, the scribe plates had to be retrieved from the field, replaced with freshly smoked scribe plates, and then individually interpreted. The new seismic monitoring system is not rendered inoperable by a seismic event. The new system has the ability to digitally record up to 90-minutes of seismic ground motion over any number of discrete seismic events. The new seismic monitoring system will automatically; analyze the earthquake data, provide a real-time display of the data analysis and its results on the system monitor, print a hard copy of the analysis results, and if the OBE is exceeded the system will also provide Control Room annunciation. Based on the changes introduced by the new seismic monitoring as discussed above, the deletion of the steps for post-seismic event activities is acceptable.

1.) TR LCO 13.3.31 delete the words, "shown in Table 13.3.31-1"

2.) Replace Condition A, including the Note with the words,

"Seismic monitoring instrument inoperable."

3.) Replace Required Action A.1 with the words,

"Restore seismic monitoring instrument to OPERABLE status."

REVISION 61 (continued)

4.) Replace the Completion Time of "24 hours" with "30 days."

5.) Delete Required Actions A.2 and A.3 and the associated Completion Times.

Delete Conditions B and C and the associated Required Actions and Completion Times.

1.) Delete the Note that says:

"Refer to Table 13.3.31-1 to determine which TRS apply for each seismic monitoring instrument."

2.) Change TRS 13.3.31.2 Frequency from 24 months to 18 months.

Delete Table 13.3.31-1 and associated foot notes

Delete the entire Bases section and replace it with the following words:

"The OPERABILITY of the seismic monitoring system ensures that sufficient capability is available to promptly determine whether the OBE has been exceeded and to collect information to evaluate the response of features important to safety. This capability is required pursuant to Appendix A of 10CFR100. The instrumentation provided meets the intent of Regulatory Guide 1.12, "Instrumentation for Earthquakes," April 1974, as described in the FSAR. The seismic monitoring system will record and analyze a seismic event to determine OBE exceedance in accordance with the requirements described in the FSAR."