UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 22, 2022

Mr. Ken J. Peters
Senior Vice President and
Chief Nuclear Officer
Attention: Regulatory Affairs
Vistra Operations Company LLC
Comanche Peak Nuclear Power Plant
6322 N FM 56
P.O. Box 1002
Glen Rose, TX 76043

SUBJECT: COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 183 AND 183 REGARDING THE ADOPTION OF TECHNICAL SPECIFICATIONS TASK FORCE TRAVELER TSTF-505, REVISION 2 (EPID L-2021-LLA-0085)

Dear Mr. Peters:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No. 183 to Facility Operating License No. NPF-87 and Amendment No. 183 to Facility Operating License No. NPF-89 for Comanche Peak Nuclear Power Plant, Unit Nos. 1 and 2, respectively. The amendments consist of changes to the technical specifications (TSs) in response to your application dated May 11, 2021, as supplemented by letters dated July 13, 2021, February 17, 2022, March 29, 2022, May 12, 2022, and July 20, 2022.

The amendments modify TS requirements to permit the use of risk-informed completion times in accordance with Technical Specifications Task Force (TSTF) Traveler TSTF-505, Revision 2, “Provide Risk-Informed Extended Completion Times – RITSTF [Risk-Informed TSTF] Initiative 4b.”

A copy of the related Safety Evaluation is also enclosed. Notice of Issuance will be included in the Commission's monthly *Federal Register* notice.

Sincerely,

/RA/

Dennis J. Galvin, Project Manager
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-445 and 50-446

Enclosures:
1. Amendment No. 183 to NPF-87
2. Amendment No. 183 to NPF-89
3. Safety Evaluation

cc: Listserv

COMANCHE PEAK POWER COMPANY LLC

AND VISTRA OPERATIONS COMPANY LLC

COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NO. 1

DOCKET NO. 50-445

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 183
License No. NPF-87

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

   A. The application for amendment by Vistra Operations Company LLC (Vistra OpCo) dated May 11, 2021, as supplemented by letters dated July 13, 2021, February 17, 2022, March 29, 2022, May 12, 2022, and July 20, 2022, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-87 is hereby amended to read as follows:

    (2) <u>Technical Specifications and Environmental Protection Plan</u>

    The Technical Specifications contained in Appendix A as revised through Amendment No. 183 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. Vistra OpCo shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. The license amendment is effective as of its date of issuance and shall be implemented within 180 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Jennifer L. Dixon-Herrity

Digitally signed by Jennifer L. Dixon-Herrity
Date: 2022.08.22 15:20:08 -04'00'

Jennifer L. Dixon-Herrity, Chief
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility
Operating License and
Technical Specifications

Date of Issuance: August 22, 2022

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

COMANCHE PEAK POWER COMPANY LLC

AND VISTRA OPERATIONS COMPANY LLC

COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NO. 2

DOCKET NO. 50-446

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 183
License No. NPF-89

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

   A. The application for amendment by Vistra Operations Company LLC (Vistra OpCo) dated May 11, 2021, as supplemented by letters dated July 13, 2021, February 17, 2022, March 29, 2022, May 12, 2022, and July 20, 2022, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-89 is hereby amended to read as follows:

    (2) Technical Specifications and Environmental Protection Plan

    The Technical Specifications contained in Appendix A as revised through Amendment No. 183 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. Vistra OpCo shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance and shall be implemented within 180 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Jennifer L. Dixon-Herrity

Digitally signed by Jennifer L. Dixon-Herrity
Date: 2022.08.22 15:20:59 -04'00'

Jennifer L. Dixon-Herrity, Chief
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility
Operating License and
Technical Specifications

Date of Issuance: August 22, 2022

ATTACHMENT TO LICENSE AMENDMENT NO. 183

TO FACILITY OPERATING LICENSE NO. NPF-87

AND AMENDMENT NO. 183

TO FACILITY OPERATING LICENSE NO. NPF-89

COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2

DOCKET NOS. 50-445 AND 50-446

Replace the following pages of Facility Operating License Nos. NPF-87 and NPF-89, and the Appendix A, Technical Specifications, with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Facility Operating License No. NPF-87

REMOVE	INSERT
3	3

Facility Operating License No. NPF-89

REMOVE	INSERT
3	3

Technical Specifications

REMOVE	INSERT	REMOVE	INSERT
1.3-8	1.3-8	3.3-18	3.3-18
---	1.3-9	3.3-19	3.3-19
---	1.3-10	3.3-20	3.3-20
3.3-1	3.3-1	3.3-21	3.3-21
3.3-3	3.3-3	3.3-22	3.3-22
3.3-4	3.3-4	3.3-23	3.3-23
3.3-6	3.3-6	3.3-24	3.3-24
3.3-7	3.3-7	3.3-25	3.3-25
3.3-8	3.3-8	3.3-26	3.3-26
3.3-9	3.3-9	3.3-27	3.3-27
3.3-10	3.3-10	3.3-28	3.3-28
3.3-11	3.3-11	3.3-42	3.3-42
3.3-12	3.3-12	3.3-43	3.3-43
3.3-13	3.3-13	3.3-44	3.3-44
3.3-14	3.3-14	3.3-45	3.3-45
3.3-15	3.3-15	3.3-46	3.3-46
3.3-16	3.3-16	3.3-47	3.3-47
3.3-17	3.3-17	3.3-48	3.3-48

Technical Specifications

REMOVE	INSERT
3.3-49	3.3-49
3.3-50	3.3-50
3.3-51	3.3-51
3.3-52	3.3-52
3.3-53	3.3-53
3.3-54	3.3-54
3.3-55	3.3-55
---	3.3-56
---	3.3-57
---	3.3-58
---	3.3-59
3.4-18	3.4-18
3.4-19	3.4-19
3.4-22	3.4-22
3.4-23	3.4-23
3.4-24	3.4-24
3.4-25	3.4-25
3.5-4	3.5-4
3.5-5	3.5-5
3.6-5	3.6-5
3.6-8	3.6-8
3.6-10	3.6-10
3.6-16	3.6-16
3.6-17	3.6-17
3.7-6	3.7-6
3.7-7	3.7-7
3.7-10	3.7-10
3.7-11	3.7-11
3.7-12	3.7-12
3.7-18	3.7-18
3.7-20	3.7-20
3.7-21	3.7-21
3.7-21a	---
3.7-45	3.7-45
3.8-2	3.8-2
3.8-4	3.8-4
3.8-4a	---
3.8-5	3.8-5
3.8-6	3.8-6

REMOVE	INSERT
3.8-7	3.8-7
3.8-8	3.8-8
3.8-9	3.8-9
3.8-10	3.8-10
3.8-11	3.8-11
3.8-12	3.8-12
3.8-13	3.8-13
3.8-14	3.8-14
3.8-15	3.8-15
3.8-16	3.8-16
3.8-17	3.8-17
3.8-18	3.8-18
3.8-19	3.8-19
3.8-20	3.8-20
3.8-21	3.8-21
3.8-22	3.8-22
3.8-23	3.8-23
3.8-24	3.8-24
3.8-25	3.8-25
3.8-26	3.8-26
3.8-27	3.8-27
3.8-28	3.8-28
3.8-29	3.8-29
3.8-30	3.8-30
3.8-31	3.8-31
3.8-32	3.8-32
3.8-33	3.8-33
3.8-34	3.8-34
3.8-35	3.8-35
3.8-36	3.8-36
3.8-37	3.8-37
3.8-38	3.8-38
3.8-39	3.8-39
3.8-40	3.8-40
---	3.8-41
5.5-17	5.5-17
---	5.5-18
---	5.5-19

(3) Vistra OpCo, pursuant to the Act and 10 CFR Part 70, to receive, possess, and use at any time, special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, and described in the Final Safety Analysis Report, as supplemented and amended;

(4) Vistra OpCo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use, at any time, any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(5) Vistra OpCo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required, any byproduct, source, and special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) Vistra OpCo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

Vistra OpCo is authorized to operate the facility at reactor core power levels not in excess of 3458 megawatts thermal through Cycle 13 and 3612 megawatts thermal starting with Cycle 14 in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A as revised through Amendment No. 183 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. Vistra OpCo shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Vistra OpCo, pursuant to the Act and 10 CFR Part 70, to receive, possess, and use at any time, special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, and described in the Final Safety Analysis Report, as supplemented and amended;

(4) Vistra OpCo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use, at any time, any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(5) Vistra OpCo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required, any byproduct, source, and special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) Vistra OpCo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

Vistra OpCo is authorized to operate the facility at reactor core power levels not in excess of 3458 megawatts thermal through Cycle 11 and 3612 megawatts thermal starting with Cycle 12 in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A as revised through Amendment No. 183 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. Vistra OpCo shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Antitrust Conditions

DELETED

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-6 (continued)

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each "Once per 8 hours thereafter" interval begins upon performance of Required Action A.1.

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-8

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Restore subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

When a subsystem is declared inoperable, Condition A is entered. The 7 day Completion Time may be applied as discussed in Example 1.3-2. However, the licensee may elect to apply the Risk Informed Completion Time Program which permits calculation of a Risk Informed Completion Time (RICT) that may be used to complete the Required Action beyond the 7 day Completion Time. The RICT cannot exceed 30 days. After the 7 day Completion Time has expired, the subsystem must be restored to OPERABLE status within the RICT or Condition B must also be entered.

The Risk Informed Completion Time Program requires recalculation of the RICT to reflect changing plant conditions. For planned changes, the revised RICT must be determined prior to implementation of the change in configuration. For emergent conditions, the revised RICT must be determined within the time limits of the Required Action Completion Time (i.e., not the RICT) or 12 hours after the plant configuration change, whichever is less.

If the 7 day Completion Time clock of Condition A has expired and subsequent changes in plant condition result in exiting the applicability of the Risk Informed Completion Time Program without restoring the inoperable subsystem to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start.

1.3 Completion Times

EXAMPLES	EXAMPLE 1.3-8 (continued) If the RICT expires or is recalculated to be less than the elapsed time since the Condition was entered and the inoperable subsystem has not been restored to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable subsystems are restored to OPERABLE status after Condition B is entered, Conditions A is exited, and therefore, the Required Actions of Condition B may be terminated.
IMMEDIATE COMPLETION TIME	When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner

3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation

LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1

ACTIONS

---NOTE---
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s) or train(s).	Immediately
B. One Manual Reactor Trip channel inoperable.	B.1 Restore channel to OPERABLE status.	48 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One Power Range Neutron Flux - High channel inoperable.	------------NOTE------------ One channel may be bypassed for up to 12 hours for surveillance testing and setpoint adjustment. ----------------------------	
	D.1.1 ----------NOTE---------- Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. ---------------------------- Perform SR 3.2.4.2.	12 hours from discovery of THERMAL POWER > 75% RTP <u>AND</u> Once per 12 hours thereafter
	<u>AND</u>	
	D.1.2 Place channel in trip.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One channel inoperable.	----------------------NOTE---------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	E.1 Place channel in trip.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
F. One Intermediate Range Neutron Flux channel inoperable.	F.1 Reduce THERMAL POWER to < P-6.	24 hours
	<u>OR</u>	
	F.2 Increase THERMAL POWER to > P-10.	24 hours
G. Two Intermediate Range Neutron Flux channels inoperable.	G.1 -----------------NOTE---------------------- Limited boron concentration changes associated with RCS inventory control or limited plant temperature changes are allowed. -- Suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>	
	G.2 Reduce THERMAL POWER to < P-6.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
M. One channel inoperable.	------------------------NOTE----------------------- One channel may be bypassed for up to 12 hours for surveillance testing. -- M.1 Place channel in trip.	 72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
N. Required Action and associated Completion Time of Condition M not met.	N.1 Reduce THERMAL POWER to < P-7.	6 hours
O. One Low Fluid Oil pressure Turbine Trip channel inoperable.	------------------------NOTE----------------------- One channel may be bypassed for up to 12 hours for surveillance testing. -- O.1 Place channel in trip.	 72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
P. One or more Turbine Stop Valve Closure Turbine Trip channel(s) inoperable.	P.1 Place channel(s) in trip.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
Q. Required Action and associated Completion Time of Condition O or P not met.	Q.1 Reduce THERMAL POWER to < P-9.	4 hours
R. One train inoperable.	------------------------NOTE----------------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. --- R.1 Restore train to OPERABLE status.	 24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
S. One RTB train inoperable.	------------------------NOTE------------------------ One train may be bypassed for up to 4 hours for surveillance testing or maintenance, provided the other train is OPERABLE. -- S.1 Restore train to OPERABLE status.	 24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
T. One or more required channel(s) inoperable.	T.1 Verify interlock is in required state for existing unit conditions.	1 hour
U. One or more required channel(s) inoperable.	U.1 Verify interlock is in required state for existing unit conditions.	1 hour
V. One trip mechanism inoperable for one RTB.	V.1 Restore trip mechanism to OPERABLE status.	48 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
W. Required Action and associated Completion Time of Condition B, D, E, R, S, T or V not met.	W.1 Be in MODE 3.	6 hours
X. Required Action and associated Completion Time of Condition U not met.	X.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.2	------------------------------NOTE------------------------------ Not required to be performed until 24 hours after THERMAL POWER is ≥ 15% RTP. -- Compare results of calorimetric heat balance calculation to NIS Power Range channel and N-16 Power Monitor channel outputs. Adjust NIS Power Range channel outputs if calorimetric heat balance calculation exceeds NIS Power Range channel outputs by more than +2% RTP. Adjust N-16 Power Monitor channel outputs if calorimetric heat balance calculation exceeds N-16 Power Monitor channel outputs by more than +2% RTP.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.3	------------------------------NOTE------------------------------ Not required to be performed until 24 hours after THERMAL POWER is ≥ 50% RTP. -- Compare results of the core power distribution measurements to Nuclear Instrumentation System (NIS) AFD. Adjust NIS channel if absolute difference is ≥ 3%.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.4	------------------------------NOTE------------------------------ This Surveillance must be performed on the reactor trip bypass breaker for the local manual shunt trip only prior to placing the bypass breaker in service. -- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.6	------------------------------NOTE------------------------------ Not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 75% RTP. --- Calibrate excore channels to agree with core power distribution measurements.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.7	------------------------------NOTES------------------------------ 1. Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. 2. Source range instrumentation shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. --- Perform COT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.8	-----------------------------------NOTE----------------------------------- This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. --- Perform COT.	---------NOTE---------- Only required when not performed within the previous Frequency specified in the SFCP. ---------------------------- Prior to reactor startup <u>AND</u> 12 hours after reducing power below P-10 for power and intermediate instrumentation <u>AND</u> Four hours after reducing power below P-6 for source range instrumentation <u>AND</u> In accordance with the Surveillance Frequency Control Program thereafter

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.9	---NOTE--- Verification of setpoint is not required. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.10	---NOTES--- 1. N-16 detectors are excluded from CHANNEL CALIBRATION. 2. This Surveillance shall include verification that the time constants are adjusted to the prescribed values. 3. Prior to entry into MODES 2 or 1, N-16 detector plateau verification is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER $\geq$ 90% RTP. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.11	---NOTES--- 1. Neutron detectors are excluded from CHANNEL CALIBRATION. 2. This Surveillance shall include verification that the time constants are adjusted to the prescribed values. 3. Prior to entry into MODES 2 or 1, power and intermediate range detector plateau verification is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 90% RTP. ------ Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.12	Not used.	
SR 3.3.1.13	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.14	---NOTE--- Verification of setpoint is not required. ------ Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.15	-----------------------------------NOTE----------------------------------- Verification of setpoint is not required. --- Perform TADOT.	 Prior to exceeding the P-9 interlock whenever the unit has been in MODE 3, if not performed in the previous Frequency specified in the SFCP
SR 3.3.1.16	-----------------------------------NOTE----------------------------------- Neutron and N-16 detectors are excluded from response time testing. --- Verify RTS RESPONSE TIMES are within limits.	 In accordance with the Surveillance Frequency Control Program.

Table 3.3.1-1 (page 1 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.14	NA
	3[(b)], 4[(b)], 5[(b)]	2	C	SR 3.3.1.14	NA
2. Power Range Neutron Flux					
a. High	1,2	4	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.11 SR 3.3.1.16	≤ 109.6% RTP[(q)(r)]
b. Low	1[(c)], 2	4	E	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11 SR 3.3.1.16	≤ 25.6% RTP[(q)(r)]
3. Power Range Neutron Flux Rate High Positive Rate	1,2	4	E	SR 3.3.1.7 SR 3.3.1.11 SR 3.3.1.16	≤ 6.3% RTP with time constant ≥ 2 sec
4. Intermediate Range Neutron Flux	1[(c)], 2[(d)]	2	F,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 31.5% RTP

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Control System capable of rod withdrawal or one or more rods not fully inserted.
(c) Below the P-10 (Power Range Neutron Flux) interlock.
(d) Above the P-6 (Intermediate Range Neutron Flux) interlock.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.1-1 (page 2 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
5. Source Range Neutron Flux	2[e]	2	I,J	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 1.4 E5 cps
	3[b], 4[b], 5[b]	2	J,K	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≤ 1.4 E5 cps
6. Overtemperature N-16	1,2	4	E	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	Refer to Note 1[q][r]
7. Overpower N-16	1,2	4	E	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≤ 112.8% RTP [q][r]
8. Pressurizer Pressure					
a. Low	1[g]	4	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 1863.6 psig (Unit 1) ≥ 1865.2 psig (Unit 2)
b. High	1,2	4	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≤ 2400.8 psig (Unit 1) ≤ 2401.4 psig (Unit 2)

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Control System capable of rod withdrawal or one or more rods not fully inserted.
(e) Below the P-6 (Intermediate Range Neutron Flux) interlock.
(g) Above the P-7 (Low Power Reactor Trips Block) interlock.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.1-1 (page 3 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
9. Pressurizer Water Level - High	1(g)	3	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 93.9% of instrument span
10. Reactor Coolant Flow - Low	1(g)	3 per loop	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 88.6% of indicated loop flow (Unit 1) ≥ 88.8% of indicated loop flow (Unit 2)
11. Not Used					
12. Undervoltage RCPs	1(g)	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 4753 V
13. Underfrequency RCPs	1(g)	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 57.06 Hz
14. Steam Generator (SG) Water Level Low-Low (l)	1, 2	4 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 37.5% of narrow range instrument span (Unit 1) (q)(r) ≥ 34.9% of narrow range instrument span (Unit 2)(q)(r)
15. Not Used.					

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.

(g) Above the P-7 (Low Power Reactor Trips Block) interlock.

(l) The applicable MODES for these channels in Table 3.3.2-1 are more restrictive.

(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.1-1 (page 4 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
16. Turbine Trip					
a. Low Fluid Oil Pressure	1(j)	3	O	SR 3.3.1.10 SR 3.3.1.15	≥ 46.6 psig
b. Turbine Stop Valve Closure	1(j)	4	P	SR 3.3.1.10 SR 3.3.1.15	≥ 1% open
17. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	R	SR 3.3.1.14	NA
18. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2(e)	2	T	SR 3.3.1.11 SR 3.3.1.13	≥ 6E-11 amp
b. Low Power Reactor Trips Block, P-7	1	1 per train	U	SR 3.3.1.5	NA
c. Power Range Neutron Flux, P-8	1	4	U	SR 3.3.1.11 SR 3.3.1.13	≤ 50.7% RTP
d. Power Range Neutron Flux, P-9	1	4	U	SR 3.3.1.11 SR 3.3.1.13	≤ 52.7% RTP
e. Power Range Neutron Flux, P-10	1,2	4	T	SR 3.3.1.11 SR 3.3.1.13	≥ 7.3% RTP and ≤ 12.7% RTP
f. Turbine First Stage Pressure, P-13	1	2	U	SR 3.3.1.10 SR 3.3.1.13	≤ 12.7% turbine power
19. Reactor Trip Breakers(RTBs)(k)	1,2	2 trains	S	SR 3.3.1.4	NA
	3(b), 4(b), 5(b)	2 trains	C	SR 3.3.1.4	NA

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Contol System capable of rod withdrawal or one or more rods not fully inserted.
(e) Below the P-6 (Intermediate Range Neutron Flux) interlock.
(j) Above the P-9 (Power Range Neutron Flux) interlock.
(k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 5 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms[k]	1,2	1 each per RTB	V	SR 3.3.1.4	NA
	3[b], 4[b], 5[b]	1 each per RTB	C	SR 3.3.1.4	NA
21. Automatic Trip Logic	1,2	2 trains	R	SR 3.3.1.5	NA
	3[b], 4[b], 5[b]	2 trains	C	SR 3.3.1.5	NA

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Contol System capable of rod withdrawal or one or more rods not fully inserted.
(k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 6 of 6)
Reactor Trip System Instrumentation

Note 1: Overtemperature N-16

The Overtemperature N-16 Function Allowable Values shall not exceed the following setpoint by more than 0.5% N-16 span for N-16 input, 0.5% T_{cold} span for T_{cold} input, 0.5% pressure span for pressure input, and 0.5% Δq span for Δq input.

$$Q_{setpoint} = K_1 - K_2\left[\frac{(1+\tau_1 S)}{(1+\tau_2 S)}T_c - T_c^{\circ}\right] + K_3(P - P^1) - f_1(\Delta q)$$

Where:

$Q_{setpoint}$ = Overtemperature N-16 trip setpoint

K_1 = *

K_2 = */°F

K_3 = */psig

T_C = Measured cold leg temperature, °F

T_c° = Indicated reference T_C at RATED THERMAL POWER, *°F

P = Measured pressurizer pressure, psig

P^1 ≥ * psig (Nominal RCS operating pressure)

s = the Laplace transform operator, sec^{-1}.

τ_1, τ_2 = Time constants utilized in lead-lag controller for T_c, $\tau_1 \geq$ * sec, and $\tau_2 \leq$ * sec

$f_1(\Delta q)$ = *{(q_t - q_b) + *%} when (q_t - q_b) ≤ *% RTP
0% when *% RTP < (q_t - q_b) < *% RTP
*{(q_t - q_b) - *%} when (q_t - q_b) ≥ *% RTP

* as specified in the COLR

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1

ACTIONS

--NOTE--
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One channel or train inoperable.	B.1 Restore channel or train to OPERABLE status.	48 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	-----NOTE----- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---------- C.1 Restore train to OPERABLE status.	 24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
D. One channel inoperable.	-----NOTE----- One channel may be bypassed for up to 12 hours for surveillance testing. ---------- D.1 Place channel in trip.	 72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
E. One Containment Pressure channel inoperable.	-----NOTE----- One channel may be bypassed for up to 12 hours for surveillance testing. ---------- E.1 Place channel in bypass.	 72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One channel or train inoperable.	F.1 Restore channel or train to OPERABLE status.	48 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
G. One train inoperable.	----------------------NOTE----------------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. --- G.1 Restore train to OPERABLE status.	 24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
H. One train inoperable.	----------------------NOTE----------------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. --- H.1 Restore train to OPERABLE status.	 24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. One channel inoperable.	----------------------NOTE---------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	I.1 Place channel in trip.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
J. One Main Feedwater Pump trip channel inoperable.	J.1 Place channel in trip.	6 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
K. One channel inoperable.	----------------------NOTE---------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	K.1 Place channel in bypass.	72 hours
L. One or more channels inoperable.	L.1 Verify interlock is in required state for existing unit condition.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
M. Required Action and associated Completion Time of Conditions B, C, or K not met.	M.1 Be in MODE 3. <u>AND</u> M.2 Be in MODE 5.	6 hours 36 hours
N. Required Action and associated Completion Time of Conditions D, E, F, G, or L not met.	N.1 Be in MODE 3. <u>AND</u> N.2 Be in MODE 4.	6 hours 12 hours
O. Required Action and associated Completion Time of Conditions H, I, or J not met.	O.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.3	Not Used.	
SR 3.3.2.4	Perform MASTER RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.5	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.6	Perform SLAVE RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.7	-----NOTES----- 1. Verification of relay setpoints not required. 2. Actuation of final devices not included. ---------- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.2.8	-----NOTE----- Verification of setpoint not required for manual initiation functions. ---------- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.9	-----NOTE----- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.10	-----NOTE----- Not required to be performed for the turbine driven AFW pump until 24 hours after SG pressure is ≥ 532 psig. ---------- Verify ESF RESPONSE TIMES are within limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.11	-----NOTE----- Verification of setpoint not required. ---------- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

LCO 3.3.5 The Loss of Power Diesel Generator Start Instrumentation for each Function in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

---NOTE---
Not applicable for 6.9 kV Preferred Offsite Source Undervoltage function when associated source breaker is open.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE------------- Not applicable to Automatic Actuation Logic and Actuation Relays Function ----------------------------------- One or more Functions with one channel per bus inoperable.	A.1 Place channel in trip.	6 hours ------------NOTE------------ RICT entry is not permitted when a loss of function occurs. ------------------------------- OR In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two channels per bus for the Preferred offsite source bus undervoltage function inoperable.	B.1 Restore one channel per bus to OPERABLE status.	1 hour ------------NOTE------------ RICT entry is not permitted when a loss of function occurs. -------------------------------- <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>OR</u>	
	B.2.1 Declare the Preferred offsite source inoperable.	1 hour
	<u>AND</u>	
	B.2.2 Open associated Preferred offsite source bus breaker.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two channels per bus for the Alternate offsite source bus undervoltage function inoperable.	C.1 Restore one channel per bus to OPERABLE status.	1 hour ------------NOTE------------ RICT entry is not permitted when a loss of function occurs. -------------------------------- <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>OR</u>	
	C.2.1 Declare the Alternate offsite source inoperable.	1 hour
	<u>AND</u>	
	C.2.2 Open associated Alternate offsite source bus breaker.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two channels per bus for the 6.9 kV bus loss of voltage function inoperable.	D.1 Restore one channel per bus to OPERABLE status.	1 hour ------------NOTE------------ RICT entry is not permitted when a loss of function occurs. -------------------------------- OR In accordance with the Risk Informed Completion Time Program
	OR	
	D.2 Declare the affected AC emergency buses inoperable.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two channels per bus for one or more degraded voltage or low grid undervoltage function inoperable	E.1 Restore one channel per bus to OPERABLE status.	1 hour ------------NOTE------------ RICT entry is not permitted when a loss of function occurs. -------------------------------- <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>OR</u>	
	E.2.1 Declare both offsite power source buses inoperable.	1 hour
	<u>AND</u>	
	E.2.2 Open offsite power source breakers to the associated buses.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One or more Automatic Actuation Logic and Actuation Relays trains inoperable.	F.1 Restore train(s) to OPERABLE status.	1 hour ------------NOTE------------ RICT entry is not permitted when a loss of function occurs. -------------------------------- <u>OR</u> In accordance with the Risk Informed Completion Time Program
G. Required Action and associated Completion Time not met.	G.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	Perform ACTUATION LOGIC TEST.	Prior to entering MODE 4 when in MODE 5 for ≥ 72 hours and if not performed in the previous Frequency specified in the SFCP
SR 3.3.5.2	----------------------------------NOTE---------------------------------- Setpoint verification is not applicable. --- Perform TADOT.	Prior to entering MODE 4 when in MODE 5 for ≥ 72 hours and if not performed in the previous Frequency specified in the SFCP
SR 3.3.5.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.5.4	Verify LOP DG start ESF RESPONSE TIMES are within limits.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.5-1 (page 1 of 1)
Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Automatic Actuation Logic and Actuation Relays	2 trains	3.3.5.1	NA
2. Preferred offsite source bus undervoltage	2 per bus	3.3.5.2 3.3.5.3	≤ 5580 V and ≥ 5040 V
3. Alternate offsite source bus undervoltage	2 per bus	3.3.5.2 3.3.5.3	≤ 5580 V and ≥ 5040 V
4. 6.9 kv Class 1E bus undervoltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≤ 2115 V
5. 6.9 kv Class 1E bus degraded voltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≥ 6024 V
6. 480 V Class 1E bus low grid undervoltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≥ 439 V
7. 480 V Class 1E bus degraded voltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≥ 439 V

3.3 INSTRUMENTATION

3.3.6 Containment Ventilation Isolation Instrumentation

LCO 3.3.6 The Containment Ventilation Isolation instrumentation for each Function in Table 3.3.6-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6-1

ACTIONS

--NOTE--
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One radiation monitoring channel inoperable.	A.1 Restore the affected channel to OPERABLE status.	4 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. --------------NOTE------------- Only applicable in MODE 1, 2, 3, or 4. ------------------------------------	-----------------------NOTE------------------------ For Required Action and associated Completion Time of Condition A not met, the containment pressure relief valves may be opened in compliance with the gaseous effluent monitoring instrumentation requirements in Part I of the ODCM. --	
One or more Automatic Actuation Logic and Actuation Relays trains inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A not met.	B.1 Enter applicable Conditions and Required Actions of LCO 3.6.3, "Containment Isolation Valves," for containment ventilation isolation valves made inoperable by isolation instrumentation.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. --------------NOTE------------- Only applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. -----------------------------------	-----------------------NOTE------------------------ The containment pressure relief valves may be opened in compliance with the gaseous effluent monitoring instrumentation requirements in Part I of the ODCM. ---	
Required Action and associated Completion Time for Condition A not met.	C.1 Place and maintain containment ventilation valves in closed position.	Immediately
	OR	
	C.2 Enter applicable Conditions and Required Actions of LCO 3.9.4, "Containment Penetrations," for containment ventilation isolation valves made inoperable by isolation instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

--NOTE--
Refer to Table 3.3.6-1 to determine which SRs apply for each Containment Ventilation Isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.2	Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.3	Perform MASTER RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.4	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.5	Perform SLAVE RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.6	Not Used.	
SR 3.3.6.7	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.6-1 (page 1 of 1)
Containment Ventilation Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Initiation	1, 2, 3, 4	Refer to LCO 3.3.2 “ESFAS Instrumentation,” Functions 2.a and 3.a.1, respectively for all initiation functions and requirements.		
2. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	SR 3.3.6.2 SR 3.3.6.3 SR 3.3.6.5	NA
3. Containment Radiation				
a. Gaseous	1, 2, 3, 4, (b), (c)	1	SR 3.3.6.1 SR 3.3.6.4 SR 3.3.6.7	(a)
4. Containment Isolation - Phase A	Refer to LCO 3.3.2, “ESFAS Instrumentation,” Function 3.a, for all initiation functions and requirements.			

(a) Must satisfy Gaseous Effluent Dose Rate Requirements in Part I of the ODCM.
(b) During CORE ALTERATIONS.
(c) During movement of irradiated fuel assemblies within containment.

3.3 INSTRUMENTATION

3.3.7 Control Room Emergency Filtration System (CREFS) Actuation Instrumentation

LCO 3.3.7 The CREFS actuation instrumentation for each Function in Table 3.3.7-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.7-1

ACTIONS

-----NOTE-----
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel or train inoperable.	A.1 Place the affected CREFS train(s) in emergency recirculation mode.	7 days
	<u>OR</u>	
	A.2 -----NOTE----- Applicable only to Functions 3a and 3b. ----------	
	Secure the Control Room makeup air supply fan from the affected air intake.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more Functions with two channels or two trains inoperable.	B.1.1 Place one CREFS train in emergency recirculation mode.	Immediately
	<u>AND</u>	
	B.1.2 Enter applicable Conditions and Required Actions for one CREFS train made inoperable by inoperable CREFS actuation instrumentation	Immediately
	<u>OR</u>	
	B.2 -----------------NOTE------------------ Applicable only to Functions 3a and 3b. ---	
	Secure the Control Room makeup air supply fan from the affected air intake.	Immediately
C. Required Action and associated Completion Time for Condition A or B not met in MODE 1, 2, 3, or 4.	C.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	C.2 Be in MODE 5.	36 hours
D. Required Action and associated Completion Time for Condition A or B not met in MODE 5 or 6, or during movement of irradiated fuel assemblies.	D.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	D.2 Suspend movement of irradiated fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

--NOTE--
Refer to Table 3.3.7-1 to determine which SRs apply for each CREFS Actuation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.7.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.7.2	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.7.3	Not Used.	
SR 3.3.7.4	Not Used.	
SR 3.3.7.5	Not Used.	
SR 3.3.7.6	-----------------------------------NOTE----------------------------------- Verification of setpoint is not required. -- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.7.7	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.7-1 (page 1 of 1)
CREFS Actuation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Initiation	1, 2, 3, 4, 5, and 6, (a)	2 trains	SR 3.3.7.6	NA
2. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4, 5, and 6, (a)	2 trains	SR 3.3.7.2	NA
3. Control Room Radiation				
a. Control Room Air North Intake	1, 2, 3, 4, 5, and 6, (a)	2	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.7	1.4×10^{-4} μCi/ml
b. Control Room Air South Intake	1, 2, 3, 4, 5, and 6, (a)	2	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.7	1.4×10^{-4} μCi/ml
4. Safety Injection	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 1, for all initiation functions and requirements.			

(a) During movement of irradiated fuel assemblies.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with:

a. Pressurizer water level ≤ 92%; and

b. Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 150 kW.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressurizer water level not within limit.	A.1 Be in MODE 3.	6 hours
	AND	
	A.2 Fully insert all rods.	6 hours
	AND	
	A.3 Place Rod Control System in a condition incapable of rod withdrawal.	6 hours
	AND	
	A.4 Be in MODE 4.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required group of pressurizer heaters inoperable.	B.1 Restore required group of pressurizer heaters to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ 92%.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.9.2	Verify capacity of each required group of pressurizer heaters is ≥ 150 kW.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

LCO 3.4.11 Each PORV and associated block valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

---NOTE---
Separate Condition entry is allowed for each PORV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more PORVs inoperable and capable of being manually cycled.	A.1 Close and maintain power to associated block valve.	1 hour
B. One PORV inoperable and not capable of being manually cycled.	B.1 Close associated block valve.	1 hour
	AND	
	B.2 Remove power from associated block valve.	1 hour
	AND	
	B.3 Restore PORV to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One block valve inoperable.	-----------------------NOTE------------------------ Required Actions do not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2. ---	
	C.1 Place associated PORV in manual control.	1 hour
	AND	
	C.2 Restore block valve to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 4	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two PORVs inoperable and not capable of being manually cycled.	E.1 Close associated block valves.	1 hour
	<u>AND</u>	
	E.2 Remove power from associated block valves.	1 hour
	<u>AND</u>	
	E.3 Be in MODE 3	6 hours
	<u>AND</u>	
	E.4 Be in MODE 4	12 hours
F. More than one block valve inoperable.	-----------------------NOTE------------------------ Required Actions do not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2. ---	
	F.1 Place associated PORVs in manual control.	1 hour
	<u>AND</u>	
	F.2 Restore one block valve to OPERABLE status	2 hours
G. Required Action and associated Completion Time of Condition F not met.	G.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	G.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.11.1	-----NOTES----- 1. Not required to be performed with block valve closed in accordance with the Required Action of this LCO. 2. Not required to be performed prior to entry into MODE 3. ---------- Perform a complete cycle of each block valve.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.11.2	-----NOTE----- Not required to be performed prior to entry into MODE 3. ---------- Perform a complete cycle of each PORV.	In accordance with the Surveillance Frequency Control Program.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS -- Operating

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

---NOTES---

1. In MODE 3, both safety injection (SI) pump flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1.

2. Operation in MODE 3 with ECCS pumps made incapable of injecting, pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is allowed for up to 4 hours or until the temperature of all RCS cold legs exceeds 375°F, whichever comes first.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One train inoperable because of the inoperability of a centrifugal charging pump.	A.1 Restore pump to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more trains inoperable for reasons other than one inoperable centrifugal charging pump. <u>AND</u> At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	B.1 Restore train(s) to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify the following valves are in the listed position with power to the valve operator removed. <u>Number</u> — <u>Position</u> — <u>Function</u> 8802 A&B — Closed — SI Pump to Hot Legs 8809 A&B — Open — RHR to Cold Legs 8835 — Open — SI Pump to Cold Legs 8840 — Closed — RHR to Hot Legs 8806 — Open — SI Pump Suction from RWST 8813 — Open — SI Pump Miniflow Valve	In accordance with the Surveillance Frequency Control Program.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1 Initiate action to evaluate overall containment leakage rate per LCO 3.6.1.	Immediately
	<u>AND</u>	
	C.2 Verify a door is closed in the affected air lock.	1 hour
	<u>AND</u>	
	C.3 Restore air lock to OPERABLE status.	24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	D.2 Be in MODE 5.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Only applicable to penetration flow paths with two containment isolation valves. ------------------------------------ One or more penetration flow paths with one containment isolation valve inoperable except for containment purge, hydrogen purge or containment pressure relief valve leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours OR In accordance with the Risk Informed Completion Time Program
	AND	
	A.2 --------------------NOTES------------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed or otherwise secured may be verified by administrative means. --- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation for isolation devices outside containment AND Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------------NOTE------------- Only applicable to penetration flow paths with only one containment isolation valve and a closed system. ------------------------------------	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND	72 hours OR In accordance with the Risk Informed Completion Time Program
One or more penetration flow paths with one containment isolation valve inoperable.	C.2 -------------------NOTES-------------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed or otherwise secured may be verified by administrative means. -- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation
D. One or more penetration flow paths with one or more containment purge, hydrogen purge or containment pressure relief valves not within leakage limits.	D.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND	24 hours

3.6 CONTAINMENT SYSTEMS

3.6.6 Containment Spray System

LCO 3.6.6 Two containment spray trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One containment spray train inoperable.	A.1 Restore containment spray train to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 84 hours
C. Two containment spray trains inoperable.	C.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.6.1	Verify each containment spray manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.6.2	Not used.	
SR 3.6.6.3	Not used.	
SR 3.6.6.4	Verify each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.6.6.5	Verify each automatic containment spray valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.6.6	Verify each containment spray pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.6.7	Not used.	
SR 3.6.6.8	Verify each spray nozzle is unobstructed.	Following maintenance which could result in nozzle blockage

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs)

LCO 3.7.2 Four MSIVs shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 except when all MSIVs are closed and deactivated.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One MSIV inoperable in MODE 1.	A.1 Restore MSIV to OPERABLE status.	8 hours OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2.	6 hours
C. --------------NOTE-------------- Separate Condition entry is allowed for each MSIV. ------------------------------------ One or more MSIV inoperable in MODE 2 or 3.	C.1 Close MSIV. AND C.2 Verify MSIV is closed.	8 hours Once per 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	---NOTE--- Only required to be performed in MODES 1 and 2. --- Verify the isolation time of each MSIV is within limits.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.7.2.2	---NOTE--- Only required to be performed in MODES 1 and 2. --- Verify each MSIV actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.4 Steam Generator Atmospheric Relief Valves (ARVs)

LCO 3.7.4 Four ARV lines shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required ARV line inoperable.	A.1 Restore required ARV line to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Two required ARV lines inoperable.	B.1 Restore at least one ARV line to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Three or more required ARV lines inoperable.	C.1 Restore at least two ARV lines to OPERABLE status.	24 hours ------------NOTE------------ RICT entry is not permitted when a loss of function occurs. -------------------------------- OR In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Verify one complete cycle of each ARV.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.7.4.2	Verify one complete cycle of each ARV block valve.	In accordance with the INSERVICE TESTING PROGRAM

3.7 PLANT SYSTEMS

3.7.5 Auxiliary Feedwater (AFW) System

LCO 3.7.5 Three AFW trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One steam supply to turbine driven AFW pump inoperable.	A.1 Restore steam supply to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. One AFW train inoperable for reasons other than Condition A.	B.1 Restore AFW train to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

3.7 PLANT SYSTEMS

3.7.7 Component Cooling Water (CCW) System

LCO 3.7.7 Two CCW trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CCW train inoperable.	-----------------------NOTE------------------------ Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," for residual heat removal loops made inoperable by CCW. -- A.1 Restore CCW train to OPERABLE status.	 72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

3.7 PLANT SYSTEMS

3.7.8 Station Service Water System (SSWS)

LCO 3.7.8 Two SSWS trains and a SSW Pump on the opposite unit with its associated cross-connects shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required SSW Pump on the opposite unit or its associated cross-connects inoperable.	A.1 Restore a SSW Pump on the opposite unit to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>AND</u>	
	A.2 Restore associated cross-connects to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One SSWS train inoperable.	--------------------NOTES-------------------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources -- Operating," for emergency diesel generator made inoperable by SSWS. 2. Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops -- MODE 4," for residual heat removal loops made inoperable by SSWS. --	
	B.1 Restore SSWS train to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. Required Action and associated Completion Time 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

3.7 PLANT SYSTEMS

3.7.19 Safety Chilled Water

LCO 3.7.19 Two safety chilled water trains shall be OPERABLE

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One safety chilled water train inoperable.	A.1 Restore safety chilled water train to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

ACTIONS

--NOTE--
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 --------------------NOTE-------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. --- Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND	
	A.3 Restore required offsite circuit to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND	
	B.4 Restore DG to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
C. Two required offsite circuits inoperable.	C.1 --------------------NOTE-------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. --- Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND	
	C.2 Restore one required offsite circuit to OPERABLE status.	24 hours OR In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One required offsite circuit inoperable. <u>AND</u> One DG inoperable.	----------------------NOTE---------------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition D is entered with no AC power source to any train. --	
	D.1 Restore required offsite circuit to OPERABLE status.	12 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>OR</u>	
	D.2 Restore DG to OPERABLE status.	12 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
E. Two DGs inoperable.	E.1 Restore one DG to OPERABLE status.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One SI sequencer inoperable.	F.1 --------------------NOTE--------------------- One required SI sequencer channel may be bypassed for up to 4 hours for surveillance testing provided the other channel is operable. --- Restore SI sequencer to OPERABLE status.	24 hours OR In accordance with the Risk Informed Completion Time Program
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met.	G.1 Be in MODE 3. AND G.2 Be in MODE 5.	6 hours 36 hours
H. Three or more required AC sources inoperable.	H.1 Enter LCO 3.0.3.	Immediately
I. One Blackout Sequencer inoperable	I.1 Declare associated DG inoperable	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.2	-----------------------------NOTES----------------------------- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. --- Verify each DG starts from standby conditions and achieves steady state voltage ≥ 6480 V and ≤ 7150 V, and frequency ≥ 59.9 Hz and ≤ 60.1 Hz.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	------------------------------NOTES------------------------------ 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2 or SR 3.8.1.7. --- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 6300 kW and ≤ 7000 kW.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.4	Verify each day tank contains ≥ 1440 gal of fuel oil.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank to the day tank.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.7	-----NOTE----- All DG starts may be preceded by an engine prelube period. ----- Verify each DG starts from standby condition and achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz; and b. steady state, voltage ≥ 6480 V and ≤ 7150 V, and frequency ≥ 59.9 Hz and ≤ 60.1 Hz.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.8	-----NOTE----- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. ----- Verify automatic and manual transfer of AC power sources from the normal offsite circuit to each alternate required offsite circuit.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.9	-----------------------------------NOTE----------------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. -- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 66.75 Hz; and b. Within 3 seconds following load rejection, the voltage is ≥ 6480 V and ≤ 7150 V.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.10	Verify each DG does not trip and voltage is maintained ≤ 8280 V during and following a load rejection of ≥ 6300 kW and ≤ 7000 kW.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	---------------------------------NOTES--------------------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. ---	
	Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in $\leq$10 seconds, 2. energizes auto-connected shutdown loads through automatic load sequencer, 3. maintains steady state voltage $\geq$ 6480 V and $\leq$ 7150 V, 4. maintains steady state frequency $\geq$ 59.9 Hz and $\leq$ 60.1 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for $\geq$ 5 minutes.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	----------NOTE---------- All DG starts may be preceded by prelube period. -------------------- Verify on an actual or simulated Safety Injection (SI) actuation signal each DG auto-starts from standby condition and; a. in ≤ 10 seconds after auto-start and during tests, achieves voltage ≥ 6480 V and frequency ≥ 58.8 Hz; b. Achieves steady state voltage ≥ 6480 V and ≤ 7150 V and frequency ≥ 59.9 Hz and ≤ 60.1 Hz; c. Operates for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.13	Verify each DG's automatic trips are bypassed on actual or simulated (i) loss of voltage signal on the emergency bus, and (ii) SI actuation signal, except: a. Engine overspeed; and b. Generator differential current.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.14	-----------------------------------NOTE----------------------------------- Momentary transients outside the load and power factor ranges do not invalidate this test. --- Verify each DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 6900 kW and ≤ 7700 kW; and b. For the remaining hours of the test loaded ≥ 6300 kW and ≤ 7000 kW.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.15	----------------------------------NOTES---------------------------------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 6300 kW and ≤ 7000 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. --- Verify each DG starts and achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz; and b. steady state, voltage ≥ 6480 V and ≤ 7150 V and frequency ≥ 59.9 Hz and ≤ 60.1 Hz.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.16	-----------------------------------NOTE----------------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. -- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.17	-----------------------------------NOTE----------------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. -- Verify, with a DG operating in test mode and connected to its bus, an actual or simulated SI actuation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.18	-----------------------------------NOTE----------------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. ---	
	Verify interval between each sequenced load block is within ± 10% of design interval for each automatic load sequencer.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	---------------------------------NOTES--------------------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. --- Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated SI actuation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in $\leq$ 10 seconds, 2. energizes auto-connected emergency loads through load sequencer, 3. achieves steady state voltage $\geq$ 6480 V and $\leq$ 7150 V, 4. achieves steady state frequency $\geq$ 59.9 Hz and $\leq$ 60.1 Hz, and 5. supplies permanently connected and auto-connected emergency loads for $\geq$ 5 minutes.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.20	------------------------NOTE------------------------ All DG starts may be preceded by an engine prelube period. -- Verify when started simultaneously from standby condition, each DG achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz, and b. steady state, voltage ≥ 6480 V, and ≤ 7150 V and frequency ≥ 59.9 Hz and ≤ 60.1 Hz.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.21	Calibrate BO sequencers.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.22	------------------------NOTES------------------------ 1. Verification of setpoint is not required. 2. Actuation of final devices is not included. -- Perform TADOT for SI and BO sequencers.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources -- Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution subsystem required by LCO 3.8.10, "Distribution Systems -- Shutdown"; and

b. One diesel generator (DG) capable of supplying one train of the onsite Class 1E AC electrical power distribution subsystems required by LCO 3.8.10.

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	------------------------NOTE------------------------ Enter applicable Conditions and Required Actions of LCO 3.8.10, with the required train de-energized as a result of Condition A. --	
	A.1 Declare affected required feature(s) with no offsite power available inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	<u>AND</u>	
	A.2.4 Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required DG inoperable.	B.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	B.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	B.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	<u>AND</u>	
	B.4 Initiate action to restore required DG to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
---NOTE--- The following SRs are not required to be performed: SR 3.8.1.3, SR 3.8.1.9 through SR 3.8.1.11, SR 3.8.1.14, SR 3.8.1.15, and SR 3.8.1.16.		
SR 3.8.2.1	For AC sources required to be OPERABLE, the following SRs are applicable: SR 3.8.1.1 SR 3.8.1.5 SR 3.8.1.10 SR 3.8.1.2 SR 3.8.1.6 SR 3.8.1.11 (except c.2) SR 3.8.1.3 SR 3.8.1.7 SR 3.8.1.14 SR 3.8.1.4 SR 3.8.1.9 SR 3.8.1.15 SR 3.8.1.16	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

LCO 3.8.3 The stored diesel fuel oil, lube oil, and starting air subsystem shall be within limits for each required diesel generator (DG).

APPLICABILITY: When associated DG is required to be OPERABLE.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each DG.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more DGs with fuel level < a 7 day supply and > a 6 day supply in storage tank.	A.1 Restore fuel oil level to within limits.	48 hours
B. One or more DGs with lube oil inventory < a 7 day supply and > a 2 day supply.	B.1 Restore lube oil inventory to within limits.	48 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more DGs with stored fuel oil total particulates not within limit.	C.1 Restore fuel oil total particulates within limit.	7 days
D. One or more DGs with new fuel oil properties not within limits.	D.1 Restore stored fuel oil properties to within limits.	30 days
E. Required Action and associated Completion Time not met. <u>OR</u> One or more DGs diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than Condition A, B, C or D.	E.1 Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify each fuel oil storage tank contains ≥ a 7 day supply of fuel.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.2	------------------------------NOTE------------------------------ Not required to be performed until the engine has been shutdown for > 10 hours. --- Verify lubricating oil inventory is ≥ a 7 day supply	 In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.3	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
SR 3.8.3.4	Verify each required DG air start receiver pressure is ≥ 180 psig.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.5	Check for and remove accumulated water from each fuel oil storage tank.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources -- Operating

LCO 3.8.4 The Train A and Train B DC electrical power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two required battery chargers on one train inoperable.	A.1 Restore affected battery(ies) terminal voltage to greater than or equal to the minimum established float voltage.	2 hours
	<u>AND</u>	
	A.2 Verify affected battery(ies) float current ≤ 2 amps.	Once per 12 hours
	<u>AND</u>	
	A.3 Restore required battery charger(s) to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or two batteries on one train inoperable.	B.1 Restore affected battery(ies) to OPERABLE status.	2 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. One DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore DC electrical power subsystem to OPERABLE status.	2 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
D. Required Action and Associated Completion Time not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is greater than or equal to the minimum established float voltage.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.4.2	Verify each battery charger supplies ≥ 300 amps at greater than or equal to the minimum established charger test voltage for ≥ 8 hours. OR Verify each battery charger can recharge the battery to the fully charged state within 24 hours while supplying the largest combined demands of the various continuous steady state loads, after a battery discharge to the bounding design basis event discharge state.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.4.3	----------------------------------NOTES---------------------------------- 1. The modified performance discharge test in SR 3.8.6.6 may be performed in lieu of SR 3.8.4.3. 2. Verify requirement during MODES 3, 4, 5, 6 or with core off-loaded. --- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources -- Shutdown

LCO 3.8.5 The Train A or Train B DC electrical power subsystem shall be OPERABLE to support one train of the DC electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems -- Shutdown."

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required DC electrical power subsystems inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	A.2.4 Initiate action to restore required DC electrical power subsystem to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.5.1	-----------------------------------NOTE----------------------------------- The following SRs are not required to be performed: SR 3.8.4.2 and SR 3.8.4.3. --	
	For DC sources required to be OPERABLE, the following SRs are applicable: SR 3.8.4.1 SR 3.8.4.2 SR 3.8.4.3.	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Battery Parameters

LCO 3.8.6 Battery parameters for Train A and Train B batteries shall be within limits.

APPLICABILITY: When associated DC electrical power subsystems are required to be OPERABLE.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each battery.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two batteries on one train with one or more battery cells float voltage < 2.07 V.	A.1 Perform SR 3.8.4.1 <u>AND</u> A.2 Perform SR 3.8.6.1 <u>AND</u> A.3 Restore affected cell(s) float voltage $\geq$ 2.07 V.	2 hours 2 hours 24 hours
B. One or two batteries on one train with float current > 2 amps.	B.1 Perform SR 3.8.4.1 <u>AND</u> B.2 Restore affected battery(ies) float current to $\leq$ 2 amps.	2 hours 12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------------NOTE------------ Required Action C.2 shall be completed if electrolyte level was below the top of plates. ------------------------------------ One or two batteries on one train with one or more cells electrolyte level less than minimum established design limits.	------------------------NOTE----------------------- Required Actions C.1 and C.2 are only applicable if electrolyte level was below the top of plates. --- C.1 Restore affected cell(s) electrolyte level to above the top of the plates. <u>AND</u> C.2 Verify no evidence of leakage. <u>AND</u> C.3 Restore affected cell(s) electrolyte level to greater than or equal to minimum established design limits.	 8 hours 12 hours 31 days
D. One or two batteries on one train with pilot cell electrolyte temperature less than minimum established design limits.	D.1 Restore battery pilot cell(s) electrolyte temperature to greater than or equal to minimum established design limits.	12 hours
E. One or more batteries in redundant trains with battery parameters not within limits.	E.1 Restore battery parameters for batteries in one train to within limits.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met. <u>OR</u> One or two batteries on one train with one or more battery cells float voltage < 2.07 V and float current > 2 amps.	F.1 Declare associated battery(ies) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.6.1	-----------------------------------NOTE----------------------------------- Not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1 -- Verify each battery float current is ≤ 2 amps.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.6.2	Verify each battery pilot cell voltage is ≥ 2.07 V.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.6.3	Verify each battery connected cell electrolyte level is greater than or equal to minimum established design limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.6.4	Verify each battery pilot cell temperature is greater than or equal to minimum established design limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.6.5	Verify each battery connected cell voltage is ≥ 2.07 V.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.6.6	-----NOTE----- Verify requirement during MODES 3, 4, 5, 6 or with core off-loaded. ----- Verify battery capacity is ≥ 80 % of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	In accordance with the Surveillance Frequency Control Program. AND 18 months when battery shows degradation or has reached 85% of expected life with capacity < 100% of manufacturer's rating AND 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters -- Operating

LCO 3.8.7 The required Train A and Train B inverters shall be OPERABLE.

---NOTE---
Inverters may be disconnected from one DC bus for ≤ 24 hours to perform an equalizing charge on their associated common battery, provided:

a. The associated AC vital bus(es) are energized; and

b. All other AC vital buses are energized from their associated OPERABLE inverters.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required inverter inoperable.	A.1 ---------------------NOTE-------------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating" with any vital bus de-energized. --- Restore inverter to OPERABLE status.	 24 hours OR In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct inverter voltage, and alignment to required AC vital buses.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 Inverters Shutdown

LCO 3.8.8 The Train A or Train B inverters shall be OPERABLE to support one train of the onsite Class 1E AC vital bus electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems -- Shutdown."

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required inverters inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	A.2.4 Initiate action to restore required inverters to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct inverter voltage and alignments to required AC vital buses.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems -- Operating

LCO 3.8.9 Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. One AC vital bus subsystem inoperable.	B.1 Restore AC vital bus subsystem to OPERABLE status.	2 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One DC electrical power distribution subsystem inoperable.	C.1 Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 5.	6 hours 36 hours
E. Two trains with inoperable distribution subsystems that result in a loss of safety function.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.10 Distribution Systems -- Shutdown

LCO 3.8.10 The necessary portion of the Train A or Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE to support one train of equipment required to be OPERABLE.

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required AC, DC, or AC vital bus electrical power distribution subsystems inoperable.	A.1 Declare associated supported required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.4 Initiate actions to restore required AC, DC, and AC vital bus electrical power distribution subsystems to OPERABLE status. AND A.2.5 Declare associated required residual heat removal subsystem(s) inoperable and not in operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.10.1	Verify correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program.

5.5 Programs and Manuals

5.5.22 Spent Fuel Storage Rack Neutron Absorber Monitoring Program

The Region I storage cells in the CPNPP Spent Fuel Pool utilize the neutron absorbing material BORAL, which is credited in the Safety Analysis to ensure the limitations of Technical Specification 4.3.1.1 are maintained.

In order to ensure the reliability of the Neutron Poison material, a monitoring program is required to routinely confirm that the assumptions utilized in the criticality analysis remain valid and bounding. The Neutron Absorber Monitoring Program is established to monitor the integrity of neutron absorber test coupons periodically as described below.

A test coupon "tree" shall be maintained in each SFP. Each coupon tree originally contained 8 neutron absorber surveillance coupons. Detailed measurements were taken on each of these 16 coupons prior to installation, including weight, length, width, thickness at several measurement locations, and B-10 content (g/cm^2). These coupons shall be maintained in the SFP to ensure they are exposed to the same environmental conditions as the neutron absorbers installed in the Region I storage cells, until they are removed for analysis.

One test coupon from each SFP shall be periodically removed and analyzed for potential degradation, per the following schedule. The schedule is established to ensure adequate coupons are available for the planned life of the storage racks.

Year	Coupon Number	Year	Coupon Number
2013	1	2028	5
2015	2	2033	6
2018	3	2043	7
2023	4	2053	8

Further evaluation of the absorber materials, including an investigation into the degradation and potential impacts on the Criticality Safety Analysis, is required if:

- A decrease of more than 5% in B-10 content from the initial value is observed in any test coupon as determined by neutron attenuation.
- An increase in thickness at any point is greater than 25% of the initial thickness at that point.

5.5 Programs and Manuals

5.5.23 Risk Informed Completion Time Program

This program provides controls to calculate a Risk Informed Completion Time (RICT) and must be implemented in accordance with NEI 06-09-A, Revision 0, "Risk-Managed Technical Specifications (RMTS) Guidelines." The program shall include the following:

a. The RICT may not exceed 30 days;

b. A RICT may only be utilized in MODE 1 and 2;

c. When a RICT is being used, any change to the plant configuration, as defined in NEI 06-09-A, Appendix A, must be considered for the effect on the RICT.

   1. For planned changes, the revised RICT must be determined prior to implementation of the change in configuration.

   2. For emergent conditions, the revised RICT must be determined within the time limits of the Required Action Completion Time (i.e., not the RICT) or 12 hours after the plant configuration change, whichever is less.

   3. Revising the RICT is not required if the plant configuration change would lower plant risk and would result in a longer RICT.

d. For emergent conditions, if the extent of condition evaluation for inoperable structures, systems, or components (SSCs) is not complete prior to exceeding the Completion Time, the RICT shall account for the increased possibility of common cause failure (CCF) by either:

   1. Numerically accounting for the increased possibility of CCF in the RICT calculation; or

   2. Risk Management Actions (RMAs) not already credited in the RICT calculation shall be implemented that support redundant or diverse SSCs that perform the function(s) of the inoperable SSCs, and, if practicable, reduce the frequency of initiating events that challenge the function(s) performed by the inoperable SSCs.

5.5 Programs and Manuals

5.5.23 Risk Informed Completion Time Program (continued)

e. The risk assessment approaches and methods shall be acceptable to the NRC. The plant PRA shall be based on the as-built, as-operated, and maintained plant; and reflect the operating experience at the plant, as specified in Regulatory Guide 1.200, Revision 2. Methods to assess the risk from extending the Completion Times must be PRA methods approved for use with this program, or other methods approved by the NRC for generic use; and any change in the PRA methods to assess risk that are outside these approval boundaries require prior NRC approval.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 183 TO

FACILITY OPERATING LICENSE NO. NPF-87

AND AMENDMENT NO. 183 TO

FACILITY OPERATING LICENSE NO. NPF-89

COMANCHE PEAK POWER COMPANY LLC

AND VISTRA OPERATIONS COMPANY LLC

COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2

DOCKET NOS. 50-445 AND 50-446

1.0 INTRODUCTION

By application dated May 11, 2021 (Reference 1), as supplemented by letters dated July 13, 2021 (Reference 2), February 17, 2022 (Reference 3), March 29, 2022 (Reference 4), May 12, 2022 (Reference 5), and July 20, 2022 (Reference 6), Vistra Operations Company, LLC, (Vistra OpCo, the licensee) submitted a license amendment request (LAR) for Comanche Peak Nuclear Power Plant Units Nos. 1 and 2 (Comanche Peak or CPNPP).
The amendments would revise technical specification (TS) requirements to permit the use of risk-informed completion times (RICTs) for actions to be taken when limiting conditions for operation (LCOs) are not met. The proposed changes are based on Technical Specifications Task Force (TSTF) Traveler TSTF-505, Revision 2, “Provide Risk-Informed Extended Completion Times – RITSTF [Risk-Informed TSTF] Initiative 4b,” dated July 2, 2018 (Reference 7). The U.S. Nuclear Regulatory Commission (NRC or the Commission) issued a final model safety evaluation (SE) approving TSTF-505, Revision 2, on November 21, 2018 (Reference 8).

The licensee has proposed variations from the TS changes described in TSTF-505, Revision 2. The variations are described in section 2.1.4 and evaluated in section 3.3 of this SE.

The NRC staff participated in a regulatory audit during November 30 and December 1, 6–8, 2021. The NRC staff performed the audit to ascertain the information needed to support its review of the application and develop requests for additional information (RAIs), as needed. On June 10, 2022, the NRC staff issued an audit summary (Reference 9). By letter and electronic mail dated June 22, 2021 (Reference 10) and March 23, 2022 (Reference 11), the NRC staff sent the licensee needs for supplemental information and RAIs, respectively. By letters dated July 13, 2021, February 17, 2022, March 29, 2022, May 12, 2022, and July 20, 2022, the licensee supplemented the application.

The supplemental letters dated February 17, 2022, March 29, 2022, May 12, 2022, and July 20, 2022, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on September 7, 2021 (86 FR 50195).

2.0 REGULATORY EVALUATION

2.1 Description of TS Changes

The TS LCOs are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When an LCO is not met, the licensee must shut down the reactor or follow any remedial or required action (e.g., testing, maintenance, or repair activity) permitted by the TSs until the condition can be met. The remedial actions (i.e., ACTIONS) associated with an LCO contain Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s) (CT). The CTs are referred to as the "front stops" in the context of this SE. For certain Conditions, the TS require exiting the Mode of Applicability of an LCO (i.e., shutdown the reactor).

The licensee's submittal requested approval to add a RICT Program to the Administrative Controls section of the TSs, and modify selected CTs to permit extending the CTs, provided risk is assessed and managed as described in Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, Revision 0-A, "Risk-Informed Technical Specifications Initiative 4b: Risk-Managed Technical Specifications (RMTS)," dated October 2012 (NEI 06-09-A) (Reference 12). NEI 06-09-A provides a methodology for extending existing CTs and thereby delay exiting the operational mode of applicability or taking "Required Actions" if risk is assessed and managed within the limits and programmatic requirements established by a RICT Program. NEI 06-09-A incorporated the NRC staff final model SE approving NEI 06-09, dated May 17, 2007 (Reference 13). The NRC issued Revision 2 to the final model SE approving NEI 06-09-A). The licensee's application proposed to use NEI 06-09-A and included documentation regarding the technical acceptability of the probabilistic risk assessment (PRA) models for the RICT Program, consistent with the guidance of Regulatory Guide (RG) 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," dated March 2009 (Reference 14).

2.1.1 TS 1.0 Use and Application

Example 1.3-8, will be added to Comanche Peak TS 1.3, “Completion Times,” and reads as follows:

EXAMPLE 1.3-8

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Restore subsystem to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

When a subsystem is declared inoperable, Condition A is entered. The 7 day Completion Time may be applied as discussed in Example 1.3-2. However, the licensee may elect to apply the Risk Informed Completion Time Program which permits calculation of a Risk Informed Completion Time (RICT) that may be used to complete the Required Action beyond the 7 day Completion Time. The RICT cannot exceed 30 days. After the 7 day Completion Time has expired, the subsystem must be restored to OPERABLE status within the RICT or Condition B must also be entered.

The Risk Informed Completion Time Program requires recalculation of the RICT to reflect changing plant conditions. For planned changes, the revised RICT must be determined prior to implementation of the change in configuration. For emergent conditions, the revised RICT must be determined within the time limits of the Required Action Completion Time (i.e., not the RICT) or 12 hours after the plant configuration change, whichever is less.

If the 7 day Completion Time clock of Condition A has expired and subsequent changes in plant condition result in exiting the applicability of the Risk Informed Completion Time Program without restoring the inoperable subsystem to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start.

If the RICT expires or is recalculated to be less than the elapsed time since the Condition was entered and the inoperable subsystem has not been restored to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable subsystems are restored to OPERABLE status after Condition B is entered, Conditions A is exited, and therefore, the Required Actions of Condition B may be terminated.

2.1.2 TS 5.5.23 – "Risk-Informed Completion Time Program"

TS 5.5.23, which describes the RICT Program, will be added to the Comanche Peak TSs and reads as follows:

Risk Informed Completion Time Program

This program provides controls to calculate a Risk Informed Completion Time (RICT) and must be implemented in accordance with NEI 06-09-A, Revision 0, "Risk-Managed Technical Specifications (RMTS) Guidelines." The program shall include the following:

a. The RICT may not exceed 30 days;

b. A RICT may only be utilized in MODE 1 and 2;

c. When a RICT is being used, any change to the plant configuration, as defined in NEI 06-09-A, Appendix A, must be considered for the effect on the RICT.

    1. For planned changes, the revised RICT must be determined prior to implementation of the change in configuration.

    2. For emergent conditions, the revised RICT must be determined within the time limits of the Required Action Completion Time (i.e., not the RICT) or 12 hours after the plant configuration change, whichever is less.

    3. Revising the RICT is not required if the plant configuration change would lower plant risk and would result in a longer RICT.

d. For emergent conditions, if the extent of condition evaluation for inoperable structures, systems, or components (SSCs) is not complete prior to exceeding the Completion Time, the RICT shall account for the increased possibility of common cause failure (CCF) by either:

    1. Numerically accounting for the increased possibility of CCF in the RICT calculation; or

2. Risk Management Actions (RMAs) not already credited in the RICT calculation shall be implemented that support redundant or diverse SSCs that perform the function(s) of the inoperable SSCs, and, if practicable, reduce the frequency of initiating events that challenge the function(s) performed by the inoperable SSCs.

e. The risk assessment approaches and methods shall be acceptable to the NRC. The plant PRA shall be based on the as-built, as-operated, and maintained plant; and reflect the operating experience at the plant, as specified in Regulatory Guide 1.200, Revision 2. Methods to assess the risk from extending the Completion Times must be PRA methods approved for use with this program, or other methods approved by the NRC for generic use; and any change in the PRA methods to assess risk that are outside these approval boundaries require prior NRC approval.

2.1.3 Application of the RICT Program to Existing LCOs and Action Statements

The typical CT is modified by the application of the RICT Program as shown in the following example. The changed portion is indicated in italics.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Restore subsystem to OPERABLE status.	7 days <u>*OR*</u> *In accordance with the Risk Informed Completion Time Program*

Where necessary, conforming changes are made to CTs to make them accurate following use of a RICT. For example, most TSs have requirements to close/isolate containment isolation devices if one or more containment penetrations have inoperable devices. This is followed by a requirement to periodically verify the penetration is isolated. By adding the flexibility to use a RICT to determine a time to isolate the penetration, the periodic verifications must then be based on the time “following isolation.”

A list of the Comanche Peak TSs and associated LCO Required Actions for the CTs proposed to be modified are below.

- TS 3.3.1 – Reactor Trip System (RTS) Instrumentation
  Action B.1
  Action D.1.2
  Action E.1
  Action M.1
  Action O.1

Action P.1
Action R.1
Action S.1
Action V.1

- TS 3.3.2 – Engineered Safety Feature Actuation System (ESFAS) Instrumentation
  Action B.1
  Action C.1
  Action D.1
  Action F.1
  Action G.1
  Action H.1
  Action I.1
  Action J.1

- TS 3.4.9 – Pressurizer
  Action B.1

- TS 3.4.11 – Pressurizer Power Operated Relief Valves (PORVs)
  Action B.3
  Action C.2

- TS 3.5.2 – ECCS [emergency core cooling systems] - Operating
  Action A.1
  Action B.1

- TS 3.6.2 – Containment Air Locks
  Action C.3

- TS 3.6.3 – Containment Isolation Valves
  Action A.1
  Action C.1

- TS 3.6.6 – Containment Spray System
  Action A.1

- TS 3.7.2 – Main Steam Isolation Valves (MSIVs)
  Action A.1

- TS 3.7.4 – Steam Generator Atmospheric Relief Valves (ARVs)
  Action A.1
  Action B.1

- TS 3.7.5 – Auxiliary Feedwater (AFW) System
  Action A.1
  Action B.1

- TS 3.7.7 – Component Cooling Water (CCW) System
  Action A.1

- TS 3.7.8 – Station Service Water System (SSWS)
  Action B.1

- TS 3.7.19 – Safety Chilled Water
  Action A.1

- TS 3.8.1 – AC [alternating current] Sources – Operating
  Action A.3
  Action B.4
  Action C.2
  Action D.1
  Action D.2
  Action F.1

- TS 3.8.4 – DC [direct current] Sources – Operating
  Action A.3
  Action B.1
  Action C.1

- TS 3.8.7 – Inverters – Operating
  Action A.1

- TS 3.8.9 – Distribution Systems – Operating
  Action A.1
  Action B.1
  Action C.1

2.1.4 Optional Changes and Variations from TSTF-505, Revision 2

2.1.4.1 Scope of TS Required Actions Included in the RICT Program

The following Comanche Peak LCO Required Actions and CTs have been modified by the proposed change to permit the application of a RICT Program and are in addition to the TS LCOs included in TSTF-505.

- TS 3.3.5 – Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation
  Action A.1
  Note *RICT entry is not permitted when a loss of function occurs.*
  Action B.1
  Note *RICT entry is not permitted when a loss of function occurs.*
  Action C.1
  Note *RICT entry is not permitted when a loss of function occurs.*
  Action D.1
  Note *RICT entry is not permitted when a loss of function occurs.*
  Action E.1
  Note *RICT entry is not permitted when a loss of function occurs.*
  Action F.1
  Note *RICT entry is not permitted when a loss of function occurs.*

- TS 3.7.4 – Steam Generator Atmospheric Relief Valves (ARVs)
  Action C.1
  Note *RICT entry is not permitted when a loss of function occurs.*

2.1.4.2 Scope of TS Required Actions Not Included in the RICT Program

The following Comanche Peak LCO Required Actions and CTs are associated with a plant-specific TS Condition that is in addition to those TS LCOs included in TSTF-505.

- TS 3.7.8 – Station Service Water System (SSWS)
  Action A.1
  Action A.2

2.1.4.3 TS Changes Not Related to TSTF-505

The licensee proposed the following additional changes to the Comanche Peak TSs.

Expired requirements, with a limited period of use (or "one-time TS changes"), will be deleted from these Required Actions:

- TS 3.7.8: Action B.1 (Note only) and Action B.2 (All)
- TS 3.7.19: Action A.2 (All)
- TS 3.8.1: Action B.4.1 (Note only) and Action B.4.2 (All)
- TS 3.8.4: Action B.2 (All)

TS 3.3.2 Condition L wording will change from "One or more required channel(s) inoperable" to "One or more channels inoperable."

TS 3.3.5 Required Action D.2 will have in its statement "A.C." revised to "AC" (alternating current).

2.2 <u>Regulatory Review</u>

2.2.1 Applicable Regulations

The regulation under Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.36(c)(2) requires that TSs contain LCOs, which are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When an LCO of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the TSs until the LCO can be met. Typically, the TSs require restoration of equipment in a timeframe commensurate with its safety significance, along with other engineering considerations. The regulation under 10 CFR 50.36(b) requires that TSs be derived from the analyses and evaluation included in the safety analysis report, and amendments thereto.

In determining whether the proposed TS remedial actions should be granted, the Commission will apply the "reasonable assurance" standards of 10 CFR 50.40(a) and 10 CFR 50.57(a)(3). The regulation at 10 CFR 50.40(a) states that in determining whether to grant the licensing request, the Commission will be guided by, among other things, consideration about whether "the processes to be performed, the operating procedures, the facility and equipment, the use of the facility, and other [TSs], or the proposals, in regard to any of the foregoing collectively provide reasonable assurance that the applicant will comply with the regulations in this chapter, including the regulations in part 20 of this chapter, and that the health and safety of the public will not be endangered."

The regulation under 10 CFR 50.36(c)(5) states, in part, that administrative controls "are the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner."

The regulation under 10 CFR 50.55a(h) "Protection and safety systems" states, in part, that "[p]rotection systems of nuclear power reactors of all types must meet the requirements specified in this paragraph."

The regulations under 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants" (i.e., the Maintenance Rule), requires licensees to monitor the performance or condition of SSCs against licensee-established goals in a manner sufficient to provide reasonable assurance that these SSCs are capable of fulfilling their intended functions. The regulation under 10 CFR 50.65(a)(4) requires the assessment and management of the increase in risk that may result from a proposed maintenance activity.

The regulation under 10 CFR 50.36(a)(1) states, in part: "[a] summary statement of the bases or reasons for such specifications other than those covering administrative controls shall also be included in the application, but shall not become part of the technical specifications." Accordingly, along with the proposed TS changes, the licensee also submitted TS bases changes that correspond to the proposed TS changes, to provide the reasons for those TSs. The TS bases changes were consistent with the bases changes in the model application dated July 2, 2018.

2.2.2 Regulatory Guidance

The NRC staff considered the following regulatory guidance during its review of the proposed changes:

- RG 1.200, Revision 2 and Revision 3

- RG 1.174, Revision 1, Revision 2, and Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated November 2002, May 2011, and January 2018, respectively (Reference 15).

- RG 1.177, Revision 0, Revision 1, and Revision 2, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998, May 2011, and January 2021, respectively (Reference 16)

- NUREG-1855, Revision 1, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decisionmaking," dated March 2017 (Reference 17).

- NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [Light-Water Reactor] Edition," section 19.2, "Review of

Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance," dated June 2007 (Reference 18).

- NUREG-0800, section 16.1, "Risk-Informed Decision Making: Technical Specifications," dated March 2007 (Reference 19)

The LAR cited RG 1.200, Revisions 2 and 3; RG 1.174, Revisions 1, 2, and 3; and RG 1.177, Revisions 0, 1, and 2. Revision 3 of RGs 1.200 and 1.174 and Revision 2 of RG 1.177 are recent updates, but do not introduce any technical discrepancies that would impact the NRC staff's review for consistency with the approval of NEI 06-09-A, therefore, the NRC staff finds RG 1.200, Revisions 2 and 3; RG 1.174 Revisions 1, 2, and 3; and RG 1.177, Revisions 0, 1, and 2, acceptable for the implementation of the RICT Program.

NRC Endorsed Guidance

NEI 06-09-A provides guidance for risk-informed TSs, which incorporates the NRC staff SE approving NEI 06-09. The NRC staff issued a final model SE approving NEI 06-09 on May 17, 2007.

3.0 TECHNICAL EVALUATION

3.1 Method of Staff Review

The NRC staff reviewed the licensee's PRA peer review history and results, alternative methods and proposed approaches to determine if they are technically acceptable for use in the proposed RICT extensions. The NRC staff also reviewed the licensee's proposed RICT Program to determine if it provides the necessary administrative controls to permit CT extensions for consistency with NEI 06-09-A.

An acceptable approach for making risk-informed decisions about proposed TS changes, including both permanent and temporary changes, is to show that the proposed licensing basis changes meet the five key principles provided in section C of RG 1.174, Revision 3, and the three tiered approach outlined in section C of RG 1.177, Revision 2. These key principles and tiers are:

Principle 1: The proposed licensing basis change meets the current regulations, unless it is explicitly related to a requested exemption.

Principle 2: The proposed licensing basis change is consistent with the defense-in-depth [DID] philosophy.

Principle 3: The proposed licensing basis change maintains sufficient safety margins.

Principle 4: When the proposed licensing basis changes result in an increase in risk, the increase should be small and consistent with the intent of the Commission's policy statement on safety goals for the operations of nuclear power plants.

- Tier 1: PRA Capability and Insights

- Tier 2: Avoidance of Risk-Significant Plant Configurations
- Tier 3: Risk-Informed Configuration Risk Management

Principle 5: The impact of the proposed licensing basis change should be monitored using performance measures strategies.

Each of these key principles and tiers are addressed in NEI 06-09-A. NEI 06-09-A provides a methodology for extending existing CTs to delay exiting the operational mode of applicability or taking Required Actions if risk is assessed and managed within the limits and programmatic requirements established by a RICT Program. The NRC staff's evaluation of the licensee's proposed use of RICTs against the principles is discussed below.

3.2 Review of Key Principles

3.2.1 Key Principle 1: Evaluation of Compliance with Current Regulations

Paragraph 50.36(c)(2) of 10 CFR requires that TSs contain LCOs, which are the lowest functional capability or performance levels of equipment required for safe operation of the facility. The CTs in the current TSs were established using experiential data, risk insights, and engineering judgment. The RICT Program provides the necessary administrative controls to permit extension of CTs and, thereby, delay reactor shutdown or Required Actions, if risk is assessed and managed appropriately within specified limits and programmatic requirements and the safety margins and DID remains sufficient. The option to determine the extended CT in accordance with the RICT Program allows the licensee to perform an integrated evaluation in accordance with the methodology prescribed in NEI 06-09-A and TS 5.5.23. The RICT is limited to a maximum of 30 days (termed the "back stop").

With the incorporation of the RICT Program, the required performance levels of equipment specified in LCOs are not changed, only the required CT for the Required Actions are modified, such that 10 CFR 50.36(c)(2) will remain met. Based on the discussion provided above, the NRC staff finds that the proposed changes meet the first key principle of RG 1.174, and RG 1.177.

3.2.2 Key Principle 2: Evaluation of DID

In RG 1.174, Revision 3, the NRC identified the following considerations used for evaluating how the licensing basis change is maintained for the DID philosophy:

- Preserve a reasonable balance among the layers of defense.
- Preserve adequate capability of design features without an overreliance on programmatic activities as compensatory measures.
- Preserve system redundancy, independence, and diversity commensurate with the expected frequency and consequences of challenges to the system, including consideration of uncertainty.
- Preserve adequate defense against potential CCFs.
- Maintain multiple fission product barriers.

- Preserve sufficient defense against human errors.

- Continue to meet the intent of the plant's design criteria.

The licensee is proposing no changes to the design of the plant or any operating parameter, and no new changes to the design-basis in the proposed changes to the TSs.

The effect of the proposed changes when implemented will allow CTs to vary based on the risk significance of the given plant configuration (i.e., the equipment out of service at any given time), provided that the system(s) retain(s) the capability to perform the applicable safety function(s) without any further failures (e.g., one train of a two -train system is inoperable). These restrictions on inoperability of all required trains of a system ensure that consistency with the DID philosophy is maintained by following existing guidance when the capability to perform TS safety function(s) is lost.

The proposed RICT Program uses plant-specific operating experience for component reliability and availability data. Thus, the allowances permitted by the RICT Program are directly reflective of actual component performance in conjunction with component risk significance.

The RICT will be applied to extend CTs on key electrical power distribution systems. Failures in electrical power distribution systems can simultaneously affect multiple safety functions; therefore, potential degradation to DID during the extended CTs is discussed further below.

The licensee has requested to use the RICT Program to extend the existing CTs for the respective TS LCOs provided in section 2.1 of this SE. The NRC staff's evaluation of the proposed changes for these LCOs assessed the plant-specific redundant or diverse means to mitigate accidents to ensure consistency with the plant licensing basis requirements.

Enclosure 1, "List of Required Actions to Corresponding PRA Functions," section 4.0, "Evaluation of Instrumentation and Control Systems," of the LAR supplement dated July 13, 2021, provided information supporting the evaluation of the redundancy, diversity, and DID of instrumentation included in the proposed TS changes. The NRC staff reviewed the trip logic arrangements, redundancy, and diverse trips for each of the protective safety functions and associated instrumentation as described in the associated Updated Final Safety Analysis Report (UFSAR) chapter 7, "Instrumentations and Controls," sections (Reference 20) and as reflected in enclosure 1, section 4.0 of the LAR supplement (e.g., LCO 3.3.1, Reactor Trip System Instrumentation). The NRC staff evaluated enclosure 1, section 4.0 of the LAR supplement using the guidance prescribed in RG 1.174, Revision 3; RG 1.177, Revision 2; and TSTF-505, to ensure adequate DID (for each of the functions) to operate the facility in the proposed manner (i.e., the changes are consistent with DID criteria).

3.2.2.1 Evaluation of Electrical Power Systems

The licensee proposed to apply the RICT Program to extend CTs on many electrical power systems required during normal plant operation. Failures in electrical power systems can simultaneously affect multiple safety functions; therefore, the NRC staff reviewed the potential of degrading DID to electrical power systems during extended CTs.

3.2.2.1.1 Electrical Power System TS Descriptions

The licensee proposed to apply the RICT Program to the following Comanche Peak electrical power systems LCOs:

TS 3.8.1 – AC Sources – Operating
TS 3.8.4 – DC [Direct Current] Sources - Operating
TS 3.8.7 – Inverters – Operating
TS 3.8.9 – Distribution Systems – Operating

The design and DID features of each the above electrical power systems are described in the Comanche Peak UFSAR chapter 8, "Electric Power," the TS Bases (Reference 20), the LAR, and the licensee's responses to electrical power system related questions (NRC Questions Nos. 20, 21, 23, 24, and 25) in the LAR supplement dated February 17, 2022).

3.2.2.1.2 Evaluations of Proposed Changes to Electrical System TS

The NRC staff evaluated whether adequate DID will be maintained during the proposed RICTs as applicable to the following TS Required Actions:

- TS 3.8.1
  Action A.3
  Action B.4
  Action C.2
  Action D.1
  Action D.2
  Action F.1

- TS 3.8.4
  Action A.3
  Action B.1
  Action C.1

- TS 3.8.7
  Action A.1

- TS 3.8.9
  Action A.1
  Action B.1
  Action C.1

The NRC staff reviewed information pertaining to the proposed TS changes in the LAR, the UFSAR, and applicable TS LCOs and TS Bases to verify the capacity and capability of the affected electrical power systems to perform their safety functions (assuming no additional failures) are maintained. The NRC staff verified that the proposed TS condition's design success criteria, as provided in table E1-1, "In Scope TS/LCO Conditions to Corresponding PRA Functions," of enclosure 1, "List of Revised Required Actions to Corresponding PRA Functions," to the LAR, reflect the redundant or absolute minimum electrical power source, component, or subsystem required to be operable to support the safety functions necessary to mitigate postulated design-basis accidents, safely shut down the reactor, and maintain the reactor in a safe shutdown condition. The NRC staff also reviewed the proposed RMA examples provided in enclosure 12, “Risk Management Action Examples,” of the LAR and LAR supplement dated February 17, 2022, for reasonable assurance that RMAs will be appropriate to monitor and control risk during the condition(s) applicable to the proposed TS changes.

3.2.2.1.3 Electrical Power Systems TS Changes Evaluation Conclusion

The NRC staff verified that the proposed changes are consistent with the DID philosophy by preserving sufficient capacity and capability of the affected electrical power systems to perform their safety functions (assuming no additional failures). The NRC staff finds that while the electrical power systems redundancy would be reduced temporarily during a RICT, the CT extensions in accordance with the RICT Program are acceptable because: (a) the capacity and capability of the electrical power systems to perform their safety functions are maintained, and (b) the licensee will identify and implement RMAs to monitor and control risk in accordance with the RICT Program. The NRC staff finds that adequate DID will be maintained during extending CTs in accordance with the RICT Program. The NRC staff finds that the licensee continues to comply with 10 CFR 50.36 when applying the proposed RICT Program to the subject electrical power systems LCOs.

3.2.2.2 Evaluation of Instrumentation and Control (I&C) Systems

The licensee proposed to apply the RICT Program to extend CTs on key I&C systems. Failures in I&C systems can simultaneously affect multiple safety functions; therefore, the NRC staff reviewed the potential for degrading DID to I&C systems during extended CTs.

3.2.2.2.1 I&C TS Descriptions

The licensee proposed to apply the RICT Program to the following Comanche Peak I&C safety systems:

TS 3.3.1 – Reactor Trip System (RTS) Instrumentation
TS 3.3.2 – Engineered Safety Feature Actuation System (ESFAS) Instrumentation
TS 3.3.5 – Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

The design and DID features of each the above safety systems is described in the Comanche Peak UFSAR chapter 7 in combination with LAR enclosure 1, table E1-1, the licensee’s responses to NRC questions ARII 4 and ARII 5 in the LAR supplement dated July 13, 2021), and the licensee’s response to question 25 and enclosure 1, “List of Required Actions to Corresponding PRA Functions, including Tables and Figures,” table E1-4, “Evaluation of Instrumentation and Control Systems,” in the LAR supplement dated February 17, 2022).

3.2.2.2.2 Loss of Function (LOF) Evaluations for I&C Systems

The NRC staff examined the number of operable channels under each RICT condition and identified the number of channels that are required to trip the specific safety function, to determine if an LOF condition exists. The following tables summarize the LOF evaluations for all risk-informed TSs.

Table I&C-1 LOF Evaluations for TS 3.3.1 “Reactor Trip System (RTS) Instrumentation”

Condition	Affected FUNCTION	# of operable channels during RICT	# of channels required to trip the safety function	LOF
B.1	1. Manual Reactor Trip	1	1	N
D.1.2	2. Power Range Neutron Flux a. High	3	2	N
E.1	2. Power Range Neutron Flux b. Low	3	2	N
E.1	3. Power Range Neutron Flux Rate High Positive Rate	3	2	N
E.1	6. Overtemperature N-16	3	2	N
E.1	7. Overpower N-16	3	2	N
E.1	8. Pressurizer Pressure b. High	3	2	N
E.1	14. Steam Generator (SG) Water Level Low-Low	3	2	N
M.1	8. Pressurizer Pressure a. Low	3	2	N
M.1	9. Pressurizer Water Level – High	2	2	N
M.1	10. Reactor Coolant Flow – Low	2	2	N
M.1	12. Undervoltage RCPs [Reactor Coolant Pumps]	3	2	N
M.1	13. Underfrequency RCPs	3	2	N
O.1	16. Turbine Trip a. Low Fluid Oil Pressure	3	2	N
P.1	16. Turbine Trip b. Turbine Stop Valve Closure	≤3	2	Y
R.1	17. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1	1	N
S.1	19. Reactor Trip Breakers (RTBs)	1	1	N
V.1	20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1	1	N

The Condition P.1 includes conditions that the 16.b trip capability could not be maintained when two more channels becomes inoperable. However, the licensee stated in the LAR supplement dated July 13, 2021, that “[t[his trip Function will not and is not required to operate in the presence of a single channel failure. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations.” The licensee further stated that, “[t]hese channels also are not a Support System for the Reactor Trip System (RTS) and as such they are not an input into the Safety Function Determination Program (SFDP). This shows that there is no loss of safety function due to the “one or more” verbiage.”

The NRC staff finds this LOF exception and its justification are acceptable.

Table I&C-2 LOF Evaluations for TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

Condition	Affected FUNCTION	# of operable channels during RICT	# of channels required to trip the safety function	LOF
B.1	1. Safety Injection a. Manual Initiation	1	1	N
B.1	2. Containment Spray a. Manual Initiation	1	1	N
B.1	3. Containment Isolation a. Phase A Isolation (1) Manual Initiation	1	1	N
B.1	3. Containment Isolation b. Phase B Isolation (1) Manual Initiation	1	1	N
C.1	1. Safety Injection b. Automatic Actuation Logic and Actuation Relays	1	1	N
C.1	2. Containment Spray b. Automatic Actuation Logic and Actuation Relays	1	1	N
C.1	3. Containment Isolation a. Phase A Isolation (2) Automatic Actuation Logic and Actuation Relays	1	1	N
C.1	3. Containment Isolation a. Phase B Isolation (2) Automatic Actuation Logic and Actuation Relays	1	1	N
C.1	7. Automatic Switchover to Containment Sump a. Automatic Actuation Logic and Actuation Relays	1	1	N
D.1	1. Safety Injection c. Containment Pressure – High 1	2	2	N
D.1	1. Safety Injection d. Pressurizer Pressure – Low	3	2	N
D.1	1. Safety Injection e. Steam Line Pressure Low	2	2	N
D.1	4. Steam Line Isolation c. Containment Pressure – High 2	2	2	N
D.1	4. Steam Line Isolation d. Steam Line Pressure (1) Low	2	2	N
D.1	4. Steam Line Isolation d. Steam Line Pressure (2) Negative Rate – High	2	2	N
D.1	6. Auxiliary Feedwater c. SG Water Level Low-Low	3	2	N
F.1	4. Steam Line Isolation a. Manual Initiation	1	1	N
F.1	6. Auxiliary Feedwater e. Loss of Offsite Power	1	1	N
F.1	8. ESFAS Interlocks a. Reactor Trip, P-4	1	1	N
G.1	4. Steam Line Isolation b. Automatic Actuation Logic and Actuation Relays	1	1	N
G.1	6. Auxiliary Feedwater a. Automatic Actuation Logic and Actuation Relays (Solid State Protection system)	1	1	N

Condition	Affected FUNCTION	# of operable channels during RICT	# of channels required to trip the safety function	LOF
H.1	5. Turbine Trip and Feedwater Isolation a. Automatic Actuation Logic and Actuation Relays	1	1	N
I.1	5. Turbine Trip and Feedwater Isolation b. SG Water Level – High (P-14)	2	2	N
J.1	6. Auxiliary Feedwater g. Trip of all Main Feedwater Pumps	3	2	N

For TS 3.3.5, a note of "RICT entry is not permitted when a loss of function occurs" is inserted to assure the RICT is not entered under the LOF conditions.

3.2.2.2.3 DID Evaluations for I&C Systems

The NRC staff evaluated the DID principle by examining whether the adequate diversity and redundancy exist with respect to the proposed changes during RICTs. The licensee summarized the diverse means in table E1-4, of enclosure 1, to the LAR supplement dated February 17, 2022, for RTS, ESFAS and LOP safety signals. In combination with the LOF evaluations, the NRC staff concludes that for each risk-informed I&C safety signal, there is either at least one redundancy, or at least one diverse means available. The NRC staff finds the proposed changes are consistent with the DID philosophy.

3.2.2.2.4 I&C Systems TS Changes Evaluation Conclusion

The NRC staff reviewed the licensee's proposed TS changes and supporting documentation. The NRC staff determines the proposed changes are consistent with the DID philosophy by preserving the diversity commensurate with the expected frequency and consequences of challenges to the system and, when applicable, by preserving adequate capability of design features without an overreliance on programmatic activities as compensatory measures. The NRC staff finds that while the I&C redundancy would be reduced temporarily during a RICT, the CT extensions implemented in accordance with the RICT Program are acceptable because: (a) the capability of the I&C systems to perform their safety functions is maintained, (b) redundant or diverse means to accomplish the safety functions exist, and (c) the licensee will identify and implement RMAs to monitor and control risk in accordance with the RICT Program. The NRC staff finds that the availability of the redundant or diverse protective features provide sufficient DID to accomplish the safety functions and would allow extending CTs in accordance with the RICT Program. The NRC staff finds that applying the proposed RICT Program to the subject I&C systems would comply with 10 CFR 50.36(b) and 10 CFR 50.55a(h).

3.2.2.3 Evaluation of CCFs

For emergent conditions, the requirements are to either (a) numerically account for the increased probability of CCF or (b) to implement RMAs that support redundant or diverse SSCs that perform the functions of the inoperable SSCs and, if practicable, reduce the frequency of initiating events that challenge the function(s) performed by the inoperable SSCs. The NRC staff finds that numerically accounting for an increased probability of failure will shorten the estimated

RICT based on the particular SSCs involved thereby limiting the time when a CCF could affect risk. Alternatively, implementing actions that can increase the availability of other mitigating SSCs or decrease the frequency of demand on the affected SSCs will decrease the likelihood that a CCF could affect risk. The NRC staff concludes that both the quantitative and the qualitative actions minimize the impact of a CCF and, therefore, support meeting the second key principle as described in RG 1.174, Revision 3. These methods either limit the exposure time, help ensure the availability of alternate SSCs, or decrease the probability of plant conditions requiring the safety function to be performed. The NRC staff finds that these methods further contribute to maintaining DID because the methods limit the exposure time or ensure the availability of alternate SSCs.

For planned conditions, the licensee stated in enclosure 9, “Key Assumptions and Sources of Uncertainty,” table 1, “Disposition of Key Sources of Assumptions and Uncertainties Related to TSTF-505,” to the LAR supplement dated February 17, 2022, that adjustments to CCF grouping and associated probabilities (Comanche Peak uses multiple Greek Letter parameters to calculate CCFs) are not performed when a component is taken out of service for preventive maintenance. It is further stated that this treatment is consistent with RG 1.177, Revision 2; and that, in lieu of making adjustments to the CCF factors, RMAs are relied upon to address potential CCFs. Section 3.3.6, “Common Cause Failure Consideration,” of NEI 06-09-A states, in part, that “for all RICT assessments of planned configurations, the treatment of common cause failures in the quantitative CRM [Configuration Risk Management] Tools may be performed by considering only the removal of the planned equipment and not adjusting common cause failure terms.” However, contrary to what is stated in the LAR supplement dated February 17, 2022, RG 1.177, Revision 2, states that when a component is rendered inoperable in order to perform preventative maintenance, the CCF contributions in the remaining operable components should be modified to remove the inoperable component and to only include CCF of the remaining components. In general, the NRC staff assessment is that the CCF contribution from the out-of-service component is conservatively retained in the following ways: (1) the independent failure rate used in the PRA models includes both independent and dependent failure events (i.e., the dependent failures should be subtracted from the total population of failures to calculate the independent failure rate) and (2) the CCF event probabilities that include the out-of-service component are retained. The NRC staff also notes, however, that this simplification produces both conservative and non-conservative effects. The CCF probability estimates are very uncertain and retaining precision in the calculation of these estimates using a more refined approach will not necessarily improve the accuracy of the results. Therefore, the NRC staff concludes that the licensee’s method is acceptable because the calculations reasonably include CCFs after removing one train for maintenance consistent with the accuracy of the estimates.

3.2.2.4 Key Principle 2: Conclusions

The NRC staff has reviewed the licensee’s proposed TS changes and supporting documentation. The NRC staff finds that extending the selected CTs with the RICT Program following loss of redundancy, but maintaining the capability of the system to perform its safety function, is an acceptable reduction in DID during the proposed RICT period provided that the licensee identifies and implements compensatory measures as appropriate during the extended CT.

The licensee confirmed in the LAR that the proposed changes do not alter the Comanche Peak system designs. Consequently, the NRC staff concludes that the proposed changes do not alter the ways in which the Comanche Peak systems fail, do not introduce new CCF modes, and the system independence is maintained. The NRC staff finds that while some proposed changes reduce the level of redundancy of the affected systems, this reduction may reduce the level of defense against some CCFs; however, such reduction in redundancy and defense against CCFs is acceptable due to existing diverse means available to maintain adequate DID against a potential single failure during a RICT.

Based on the above, the NRC staff finds that the licensee's process is consistent with the NRC-endorsed guidance prescribed in NEI 06-09-A and satisfies the second key principle of RG 1.177. Additionally, the NRC staff concludes that the proposed changes are consistent with the DID philosophy described in RG 1.174.

3.2.3 Key Principle 3: Evaluation of Safety Margins

Section 2.2.2 of RG 1.177, Revision 2, states, in part, that sufficient safety margins are maintained when:

- Codes and standards … or alternatives approved for use by the NRC are met.

- Safety analysis acceptance criteria in the final safety analysis report are met, or proposed revisions provide sufficient margin to account for analysis and data uncertainties.

The licensee is not proposing in this application to change any quality standard, material, or operating specification. In the LAR, as supplemented, the licensee proposed to add a new program (RICT Program), in section 5.0, "Administrative Controls," of the TSs, which would require adherence to NEI 06–09-A, Revision 0.

The NRC staff evaluated the effect on safety margins when the RICT is applied to extend the CT up to a backstop of 30 days in a TS condition with sufficient trains remaining operable to fulfill the TS safety function. Although the licensee will be able to have design-basis equipment out of service longer than the current TS allows any increase in unavailability is expected to be insignificant and is addressed by the consideration of the single failure criterion in the design-basis analyses. Acceptance criteria for operability of equipment are not changed and, if sufficient trains remain operable to fulfill the TS safety function, the operability of the remaining train(s) ensures that the current safety margins are maintained. The NRC staff finds that if the specified TS safety function remains operable, sufficient safety margins would be maintained during the extended CT of the RICT Program. The NRC staff has evaluated specific proposed changes to the TSs as described in section 2.1 of this SE.

Safety margins are also maintained if PRA functionality is determined for the inoperable train, which would result in an increased CT. Credit for PRA functionality, as described in NEI 06-09-A, is limited to the inoperable train, loop, or component.

Based on the above, the NRC staff finds that the design-basis analyses for Comanche Peak remain applicable and unchanged. The NRC staff concludes that the proposed change meets the third key principle of RG 1.177, Revision 2, and is acceptable.

3.2.4 Key Principle 4: Change in Risk Consistent with the Safety Goal Policy Statement

TS section 5.5.23, states, in part, that the RICT "must be implemented in accordance with NEI 06-09-A, Revision 0, 'Risk-Managed Technical Specifications (RMTS) Guidelines'".

NEI 06-09-A provides a methodology for a licensee to evaluate and manage the risk impact of extensions to TS CTs. Permanent changes to the fixed TS CTs are typically evaluated by using the three-tiered approach described in section 16.1 of NUREG-0800, RG 1.177, Revision 2, and RG 1.174, Revision 3. This approach addresses the calculated change in risk as measured by the change in core damage frequency (CDF) and large early release frequency (LERF), as well as the incremental conditional core damage probability (CCDP) and incremental conditional large early release probability (CLERP); the use of compensatory measures to reduce risk; and the implementation of a configuration risk management program (CRMP) to identify risk-significant plant configurations.

The NRC staff evaluated the licensee's processes and methodologies for determining that the change in risk from implementation of RICTs will be small and consistent with the intent of the Commission's Safety Goal Policy Statement.[1] In addition, the NRC staff evaluated the licensee's proposed changes against the three-tiered approach in RG 1.177, Revision 2, for the licensee's evaluation of the risk associated with a proposed TS CT change. The results of the NRC staff's review are discussed below.

3.2.4.1 Tier 1: PRA Capability and Insights

The first tier evaluates the impact of the proposed changes on plant operational risk. The Tier 1 review involves two aspects: (1) scope and acceptability of the PRA models and their application to the proposed changes, and (2) a review of the PRA results and insights described in the licensee's application.

Enclosure 2, "Information Supporting Consistency with Regulatory Guide 1.200," and Enclosure 4, "Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models," of the LAR supplement dated February 17, 2022, identified the following modeled hazards and alternate methodologies the licensee proposed to be used in the Comanche Peak RICT Program to assess the risk contribution for extending the CT of a TS LCO:

- Internal Events PRA (IEPRA) model (includes internal floods)

- Internal Fire PRA (FPRA) model

- Seismic Hazard: CDF penalty of 1.93E-06 per year, and a LERF penalty of 9.73E-07 per year

- Extreme Winds and Tornado Hazards: baseline high wind CDF penalty of 4.09E-06 per year and a high wind LERF penalty of 2.35E-07 per year; additional high wind penalties are applied for the RICT calculation for seven equipment out-of-service conditions

[1] Commission's Safety Goal Policy Statement, "Safety Goals for the Operations of Nuclear Power Plants; Policy Statement," published in the *Federal Register* on August 4, 1986 (51 FR 28044), as corrected, and republished, on August 21, 1986 (51 FR 30028).

- Other External Hazards: screened out from RICT Program based on appendix 6-A of the American Society of Mechanical Engineers (ASME)/American Nuclear Society (ANS) PRA Standard ASME/ANS RA-Sa-2009, "Addenda to ASME RA-S-2008, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications" (Reference 21)

3.2.4.1.1 PRA Scope

The NRC staff evaluated the PRA acceptability information provided by the licensee in enclosure 2, to the LAR supplement dated February 17, 2022, including industry peer review results and the licensee's self-assessment of the PRA models for internal events, including internal flooding, and fire, against the guidance in RG 1.200, Revision 2. The licensee screened out all external hazard events except for seismic and high winds, as described in section 3.2.4.1.3 of this SE, as insignificant contributors to RICT calculations. The Comanche Peak PRA model with modifications is used in the CRMP tool as described in section 3.2.4.1.7 of this SE. In addition, the licensee provided a bounding estimate of the seismic CDF and LERF and the high winds CDF and LERF and will include those CDF and LERF values into the change in risk used to calculate RICTs consistent with the guidance in NEI 06-09-A. For external hazards for which a PRA is not available, the guidance in NEI 06-09-A allows for the use of bounding analysis of the risk contribution of the hazard for incorporation into the RICT calculation or justification for why the hazard is not significant to the RICT calculation.

In section 4.2, "Modeling of FLEX [Flexible and Diverse Coping Strategies] (Portable) Equipment and Mitigating Actions in the PRA," of enclosure 2 to the LAR supplement dated February 17, 2022, the licensee stated that FLEX portable equipment and mitigating actions are not credited the Comanche Peak PRA models.

The NRC staff finds the Comanche Peak scope of modeled PRA hazards, and those hazards for which a modeled PRA is not available where the licensee has proposed use of alternative methods, to be commensurate with the RICT application for use in the integrated decision-making process consistent with RG 1.174, Revision 3.

3.2.4.1.2 Evaluation of PRA Acceptability for Internal Events and Internal Fires

<u>IEPRA</u>

In section 2.0, "Scope and Technical Adequacy of CPNPP Internal Events PRA Model (Including Internal Flooding)," of enclosure 2 to the LAR supplement dated February 17, 2022, the licensee stated that the Comanche Peak IEPRA model received a peer review in 2011 using NEI 05-04, Revision 2, "Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard," dated November 2008 (Reference 22), the ASME PRA Standard ASME/ANS RA-Sa-2009, and RG 1.200, Revision 2). Subsequent to the peer review, the findings and observations (F&Os) from the peer review were addressed in revisions to the IEPRA. Following these revisions, an independent assessment for closure of F&Os using appendix X to NEI 05-04, 07-12, and 12-13, "Final Revision of Appendix X to NEI 05-04/07-12/12-16, Close-Out of Facts and Observations," (Reference 23) (Appendix X guidance), as accepted, with conditions by the NRC staff (Reference 24), was performed in 2019 which resulted in closure of all of the peer review finding-level F&Os. The LAR also stated that there have been no model changes that constitute a PRA upgrade and that all but two applicable supporting requirements (SRs) are assessed to be Met at Capability Category (CC) II or III.

The remaining two SRs (i.e., IFEV-A6 and LE-C11), were assessed to be CC-I by the peer review team. The licensee provided in the LAR an assessment of the impact of these two CC-I SRs on the RICT application. The NRC staff performed a review of the licensee's assessment of these two SRs. For IFEV-A6, the licensee's internal flooding PRA uses generic industry pipe failure data to develop internal flood initiating event frequencies. In the LAR, the licensee stated that no Bayesian updating using plant-specific data has been performed because there have been no applicable internal flooding events at Comanche Peak, and that this is conservative for the RICT application. The NRC staff finds that meeting CC-I is acceptable for the RICT application as follows. The licensee not performing Bayesian updating of the internal flood initiating event frequencies when there are no plant-specific internal flooding events (1) has the effect of using internal flood initiating event frequencies that are somewhat greater than if Bayesian updating was performed and (2) does not decrease the RICT from what it would be if initiating event frequencies were Bayesian updated (i.e., if the SR was Met at CC-II).

For LE-C11, the licensee stated in the LAR that this SR meets CC-I because the Comanche Peak PRA does not credit continued operation of mitigating equipment and operator actions after containment failure. The reason given for not crediting mitigating equipment and operator actions is because there are none that are significant. However, the licensee further stated that the impact on specific applications will be evaluated as needed. In response to NRC Question 02 in the LAR supplement dated February 17, 2022, the licensee clarified that containment systems that are assumed to be failed after containment failure and that are included within the scope of the RICT Program (e.g., TS LCO 3.6.6) may be considered explicitly in the development of the RICT when they are removed from service, but that this contribution to the RICT is not expected to be significant. The NRC staff finds that meeting CC-I is acceptable for the RICT application because not crediting mitigating equipment and operator actions after containment failure is unlikely to have a significant impact on calculated RICTs.

The NRC staff finds that the Comanche Peak IEPRA was appropriately peer reviewed consistent with RG 1.200, Revision 2, F&Os were closed consistent with Appendix X guidance, as accepted, with conditions by the NRC staff, and that SRs evaluated by the peer review to be CC I have been appropriately assessed for impact on the RICT Program; therefore, the IEPRA is acceptable for use in the RICT Program.

<u>Internal Fire Events PRA</u>

In section 3.0, "Scope and Technical Adequacy of CPNPP Fire PRA Model," of enclosure 2 to the LAR supplement, dated February 17, 2022, the licensee stated that the Comanche Peak internal fire [FPRA] model received a full-scope peer review in 2016 using NEI 07-12, Revision 1, "Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines," dated June 2010 (Reference 25), the ASME PRA Standard ASME/ANS RA-Sa-2009, and RG 1.200, Revision 2.

After findings from the peer review were addressed in the FPRA model, an independent assessment was performed in 2019 consistent with RG 1.200, Revision 3. As a result of the F&O closure review, all finding-level F&Os from the peer review were resolved consistent with Appendix X guidance and, hence, no open F&Os were presented in the LAR. The LAR also states that there have been no model changes that constitute a PRA upgrade and that all applicable SRs are assessed to be CC-II or III.

In the LAR supplement, dated February 17, 2022, the licensee provided responses to NRC Questions 15 and 16 related to the FPRA, and several responses to their subparts are discussed below.

In response to Question 15a, the licensee stated that the internal events findings were reviewed and there are no outstanding exceptions or deficiencies that would adversely impact the FPRA.

In response to Question 16a, the licensee stated that only approved methodologies were utilized in the development of the FPRA.

In response to Question 16b, the licensee stated that there are no locations utilizing a reduced transient fire heat release rate and that all transients in the Comanche Peak FPRA utilized the bounding 98th percentile heat release rate of 317 kilowatts from NUREG/CR-6850, "EPRI [Electric Power Research Institute]/NRC Fire PRA Methodology for Nuclear Power Facilities," dated September 2005 (Reference 26).

In response to Question 16c, the licensee stated that it followed the guidance in FPRA Frequently Asked Question (FAQ) 13-0004, "Clarifications on Treatment of Sensitive Electronics," dated December 13, 2013 (Reference 27). While the supplement does not specifically address the treatment of sensitive electronic components mounted on the inside surface of cabinets or mounted in cabinets having louvers or other means of ventilation, based on the licensee's statement, the NRC staff deems these configurations to have been appropriately considered in the Comanche Peak FPRA.

In response to Question 16d, the licensee stated that a minimum joint probability less than 1E-05 was used in the FPRA. The licensee provided the results of a sensitivity study of increasing the joint human error probability to 1E-05, which produced fire CDF and LERF changes of less than 0.5 percent from the baseline. In the LAR supplement dated May 12, 2022, the licensee stated that the focus of the sensitivity study presented in response to Question 16d was on the delta-CDF attributable to a change in the human error probability floor value selected for use in the FPRA modeling. A plant-specific alignment was used, which was known to have a very "high CDF" alignment. This alignment accentuates the importance of fire, which results in a high CDF, and the focus of the sensitivity run was on the delta-CDF, not on the actual values of CDF. The licensee stated that this sensitivity provides reasonable assurance that a small change in CDF/LERF does not have significant impact on the RICT calculated timings. Based on these results the NRC staff finds that using a minimum joint human error probability of 1E-06 rather than 1E-05 in the FPRA has a minimal impact on the RICT application.

In response to Question 16e, the licensee stated that the guidance in NUREG-2178, "Refining and Characterizing Heat Release Rates from Electrical Enclosures During Fire (RACHELLE-FIRE) Volume 1: Peak Heat Release Rates and Effect of Obstructed Plume," dated April 2016 (Reference 28), on the use of the obstructed plume model was used and that the base of the fire was always modeled at an elevation greater than one-half of the cabinet height.

In response to Question 16f, the licensee identified several nonsafety-related components included in TS LCOs that are assumed to be failed in the FPRA and, therefore, will have no fire risk contribution to calculated RICTs if they are out of service. The components were relays that support the function of the steam dump system and motor-operated valves that isolate the non-safeguards CCW supply to thermal barrier cooling. As a result, calculated RICTs will be underestimated for configurations in which these components are out of service and, potentially, could be underestimated for other unrelated out-of-service configurations. The licensee performed a bounding sensitivity study in which the applicable components were assumed to never fail in fire scenarios. In both this sensitivity case and in the LAR case in which the components are assumed to be failed, the RICTs for directly applicable LCOs (i.e., LCO 3.3.2.C and LCO 3.6.3.A) were calculated to be greater than the 30-day backstop. A similar bounding sensitivity study was also performed assuming a centrifugal charging pump is out of service (i.e., LCO 3.3.5.A). While the centrifugal charging pump is not directly related to the functions of the assumed-failed components, it does provide alternate cooling water to the thermal barrier cooling heat exchangers and to reactor cooling pump seal injection. The calculated RICTs for both the baseline (components assumed failed) and the sensitivity cases were also greater than the 30-day backstop. Based on these results, the NRC staff finds that assuming the identified components are failed in the FPRA does not impact the RICT calculations.

In response to Question 16g, the license stated that per FPRA FAQ 14-0009, “Treatment of Well-Sealed MCC [Motor Control Center] Electrical Panels Greater than 440V [Volts],” dated April 29, 2015 (Reference 29), a factor of 0.23 was used to represent the fraction of fires that breach a well-sealed MCC cabinet operating at 440V or greater. The licensee also stated that all MCCs modeled in the FPRA are 440V or greater, and therefore, the guidance in FPRA FAQ 08-0042, “Fire Propagation from Electrical Cabinets,” dated August 4, 2009 (Reference 30), is not applicable. The NRC staff finds the licensee’s treatment of well-sealed cabinets consistent with the above guidance.

NUREG/CR-6850, Volume 2, chapter 6 and FAQ 12-0064 “Hot Work/Transient Fire Frequency Influence Factors,” dated January 17, 2013 (Reference 31), describe the process for assigning influence factors for hot work and transient fires. In response to Question 16h, the licensee stated that the NUREG/CR-6850 methodology was followed for assigning hot work/transient fire frequency influence factors. The licensee stated that administrative controls were not used to assign weighting factors. The weighting factors were developed for each fire compartment based on surveys by four knowledgeable Comanche Peak personnel. The licensee also stated that a weighting factor of “0” was not assigned to maintenance, occupancy, or storage areas and that a weighting factor of “50” was assigned to five locations per the guidance in FAQ 12-0064. The NRC staff finds the licensee’s treatment of transient fire influence factors consistent with the above guidance.

The NRC guidance in FAQ 14-0008, “Main Control Board Treatment,” dated July 22, 2014 (Reference 32), clarifies the definition of the main control board (MCB) and provides guidance for when to include the cabinets on the back side of the MCB as part of the MCB for FPRA. In response to Question 16i, the licensee described the MCB as a collection of control panels in a horseshoe configuration. There are no rear control panels. The licensee further explained that fire scenarios within the MCB are developed and modeled consistent with FAQ 14-0008. The NRC staff finds that the licensee has considered the NRC guidance in FAQ 14-0008 when modeling fire scenarios in the MCB.

In response to Question 16j, the licensee described how the risk contribution of fires originating in one unit are addressed for the other unit given impacts due to the physical proximity of equipment and cables in one unit to equipment and cables in the other unit. The licensee stated that Comanche Peak is a dual unit plant with shared auxiliary and electrical/control buildings, as well as the service water intake structure. Select Unit 1 equipment required for safe shutdown is able to cross-tie to its corresponding equipment in Unit 2 (and vice versa) to provide alternate cooling capabilities. These cross-ties are credited in the plant response model. All shared locations of the plant are modeled and analyzed for impact on each unit and included in the discussion of results. The NRC staff finds the licensee's treatment of fire dependencies between the units acceptable because the risk contribution of fires originating in one unit is addressed for the other unit.

Based on the above, the NRC staff finds that the Comanche Peak FPRA was appropriately peer reviewed consistent with RG 1.200, Revision 2, fire methodologies were appropriately considered and implemented, and all finding-level F&Os were closed consistent with the Appendix X guidance, as accepted, with conditions by the NRC staff. Therefore, the Comanche Peak FPRA is acceptable for use in the RICT Program.

3.2.4.1.3 Evaluation of PRA External Hazards Modeled

Evaluation of Seismic Hazard

The licensee's approach for including the seismic risk contribution in the RICT calculation is to add a penalty seismic CDF and a penalty seismic LERF to each RICT calculation. The proposed bounding seismic CDF estimate was based on using the plant-specific mean seismic hazard curve developed in response to the Near-Term Task Force Recommendation 2.1 (Reference 33), and a plant level mean high confidence of low probability of failure (HCLPF) capacity of 0.12g referenced to peak ground acceleration (PGA). The uncertainty parameter for seismic capacity was represented by a composite beta factor of 0.4. The calculated seismic CDF penalty is 1.93E-06 per year. The NRC staff's review finds the method to determine the baseline seismic CDF acceptable because it is consistent with the approach used in the Safety/Risk Assessment for NRC Generic Issue-199 (GI-199), "Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants," dated September 2, 2010 (Reference 34). In addition, the plant level HCLPF of 0.12g and beta factor of 0.4 used are also consistent with the values presented for Comanche Peak in table C-2, "Plant-Level Fragility Data," of appendix C of the Safety/Risk Assessment for GI-199. The NRC staff convolved the input parameters identified by the licensee to confirm the proposed bounding seismic CDF estimate.

Concerning the proposed bounding seismic LERF estimate, the licensee explained in the LAR that an estimate of the seismic LERF was obtained by convolving the estimated seismic CDF (as described above) with a limiting fragility for containment integrity, also assumed to be 0.12g PGA HCLPF because the containment fragility is not available. The calculated seismic LERF is 9.73E-07 per year. The NRC staff finds that the licensee's approach to determining a seismic LERF estimate to be acceptable because use of a 0.12g PGA HCLPF as the limiting fragility for containment integrity is conservative.

The licensee also calculated the seismically induced loss of offsite power (LOOP) frequency of 2.84E-06 per year, which is 0.02 percent of the total LOOP initiating event frequency in the IEPRA. The NRC staff evaluated the analysis and finds that the analysis adequately addresses the impact of seismically induced LOOP for very low magnitude seismic events and has an insignificant impact on the RICT Program calculations.

In summary, the NRC staff's review finds the licensee's proposal to use the seismic CDF contributions of 1.93E-06 per year, and a seismic LERF contribution of 9.73E-07 per year acceptable for the licensee's RICT Program for Comanche Peak, because (1) the licensee used the most current site-specific seismic hazard information, (2) the licensee used an acceptably low plant HCLPF value of 0.12g and a combined beta factor of 0.4 consistent with the information for Comanche Peak in the GI-199 evaluation in the convolution to develop the bounding seismic CDF, (3) the licensee used an acceptably low plant HCLPF value of 0.12g and a combined beta factor of 0.4 for the containment integrity fragility in the convolution to develop the bounding seismic, and (4) adding baseline seismic risk to RICT calculations, which assumes fully correlated failures, is conservative for SSCs credited in seismic events, while any potential non-conservative results for SSCs that are not credited in seismic events is small or nonexistent.

Evaluation of Extreme Winds and Tornado Hazards

The licensee explained in enclosure 4 to the LAR supplement dated February 17, 2022, that RICT calculations will include a risk contribution from high winds events using a "penalty" approach. This approach adds a high wind CDF and LERF to each RICT calculation. High wind CDF and LERF estimates were developed for a baseline case and seven different plant equipment out-of-service configurations. These estimates were determined as the product of the mean wind hazard frequency per year, the conditional LOOP (CLOOP) probability given a high wind event, and a CCDP or CLERP based on the plant equipment out-of-service configuration.

Mean hazard frequencies were developed for each of ten windspeed intervals for the following: (1) tornado winds, (2) straight winds generated due to thunderstorms, and (3) straight winds generated from non-thunderstorms. A separate wind hazard was not developed for hurricanes because the Comanche Peak site is located approximately 250 miles from the Gulf of Mexico and therefore, would have limited influence because of diminished strength. The licensee explained that the source of the tornado data used to develop the tornado hazard was the National Oceanic Atmospheric Administration. Tornado records striking within a 125-mile radius of the site were used, and this tornado data was adjusted to account for data uncertainties in accordance with the ASME/ANS RA-Sa-2009 PRA standard. The tornado strike occurrence frequencies for each of the wind intervals for the Comanche Peak site was then estimated using NUREG/CR-4461, Revision 2, "Tornado Climatology of the Contiguous United States," dated February 2007 (Reference 35), methods. Based on this, the NRC staff finds that the methodology for developing the straight winds and tornado hazard is reasonable for this RICT application because it uses relevant data, accounts for data uncertainty, and follows the approach in NUREG/CR-4461, Revision 2 for tornado strike occurrence frequencies.

CLOOP probabilities were estimated for each of the ten windspeed intervals using engineering judgment. In the LAR supplement dated February 17, 2022, the licensee performed a sensitivity study of the CLOOP probability assumptions by developing a fragility for the offsite power transmission grid, which is assumed to be the limiting component capable of causing a LOOP due to wind-induced damage. The fragility was developed as a lognormal distribution having a mean windspeed capacity of 96 miles per hour (mph), based on the design-basis windspeed of 80 mph for the Comanche Peak switchyard and assuming a 1.2 safety factor, and values for the modeling uncertainty parameter (β_U) and random variability parameter (β_R) of 0.075 and 0.176, respectively. Convolving this fragility with the high wind hazard and the CCDPs and CLERPs (discussed below) yields a high wind CDF and high wind LERF that are 13 percent and 14 percent lower, respectively, than the baseline results using CLOOPs based on engineering judgment. The NRC staff concludes that the licensee's assumption that the offsite power transmission grid is the limiting component, and the associated fragility estimate is reasonable because (1) the wind design criteria for Seismic Category I structures at the Comanche Peak site is 80 mph, as described in NUREG-0797, "Safety Evaluation Report related to operation of Comanche Peak Steam Electric Station, Units 1 and 2," dated July 1981 (Reference 36), and all systems and components essential for safe shutdown and maintaining the integrity of the reactor coolant pressure boundary are located with Seismic Category I buildings, as described in the Comanche Peak Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities, dated June 1994 (Reference 37), (2) the Comanche Peak switchyard is designed to withstand windspeeds in excess of 80 mph, which is also described in the IPEEE for Severe Accident Vulnerabilities, and (3) the American Society of Civil Engineers design guide for transmission line design (Reference 38) specifies a windspeed of 80 mph for the location of the Comanche Peak site. Based on this conclusion, the NRC staff finds that the CLOOP probabilities used in the development of the high wind penalty factors are reasonable, and likely conservative, for the RICT application.

The licensee calculated eight CCDP and CLERP values; one for a baseline case and seven for specific equipment out-of-service configurations. In the LAR and its supplement dated February 17, 2022, the licensee explained the development and implementation of these 8 CCDP and CLERP values. The licensee stated that components that were identified as approaching or exceeding the various risk monitor thresholds were chosen for this assessment. As listed in table E4-4, “High Winds Sequence Development Results,” of enclosure 4 of the LAR supplement dated February 17, 2022, the seven equipment out-of-service cases have higher CCDP and CLERP due to the reduced redundancy of important PRA functions in those out-of-service cases. Results show that the out-of-service configurations should not have significant contributions to the calculated RICTs. The NRC staff finds the equipment out-of-service configurations for which high winds penalty factors are developed are reasonable for the RICT application because (1) they were developed based on the peer reviewed Comanche Peak internal events PRA model, (2) the penalty factors for the represented equipment out-of-service conditions are bounding for all other equipment out-of-service configurations, (3) not including penalty factors for equipment out-of-service configurations other than those considered is not significant to calculated RICTs, and (4) implementation of a RICT is precluded for situations in which two or more of the equipment out-of-service configurations exist.

The high wind CDF and LERF for each equipment out-of-service configuration and each wind hazard is the convolution of the applicable mean wind hazard frequency per year, the applicable CLOOP probability given a high wind event and the applicable CCDP or CLERP. The high wind CDF and LERF penalties reported in the LAR for each plant equipment out-of-service configuration are the sum of the results for each of the high wind hazards. These values are listed in table E4-5, “High Winds Results Summary for CPNPP,” of enclosure 4 to the LAR supplement dated February 17, 2022. If a RICT results in a situation represented by any one of the seven out-of-service cases, the penalty value will be determined by adding the delta high wind CDF and LERF for that out-of-service case to the baseline. For all other RICTs, only the baseline high wind CDF and LERF values will be used as the penalty value.

The licensee identified several key assumptions and sources of uncertainty in the development of the penalty factors. A few of these identify conservatisms in the methodology, including (1) mitigating equipment is assumed to fail if located within a building that has failed or is located outside but may be available, especially for less-intense wind events, (2) LOOP recovery is not credited but may be possible, especially for less-intense wind events, and (3) some of the tornado data assumes that the entire tornado path is at the maximum windspeed, which is always limited to a portion of the entire path. The NRC staff finds that these assumptions and sources of uncertainty are acceptable for this application because they are likely conservative, which is appropriate for the penalty approach for the risk contribution from high winds for this application.

In summary, the NRC staff's review finds the licensee's proposal to use the high wind CDF and LERF contributions reported in the LAR acceptable for the licensee's RICT Program for Comanche Peak, because (1) the methodologies for developing the tornado and straight wind hazards use wind data specific to the Comanche Peak site and are consistent with available NRC guidance, (2) the CLOOP probabilities are reasonable and likely conservative, (3) the CCDPs and CLERPs for each of the evaluated equipment out-of-service configurations were developed based on the peer reviewed IEPRA model for Comanche Peak, (4) the potential contribution from all other equipment out-of-service configurations is not significant to calculated RICTs, (5) application of RICTs will be precluded for situations in which two or more of the evaluated equipment out-of-service configurations exist, and (6) the CCDPs and CLERPs are likely conservative based on the licensee's assessment of key assumptions and sources of uncertainty.

Evaluation of Other External Hazards

Besides seismic, and extreme winds and tornado hazards discussed above, the licensee confirmed that other external hazards for Comanche Peak have insignificant contribution and proposed these hazards to be screened out from the RICT Program. In table E4-6, "Other External Hazards Screening," of enclosure 4 to the LAR supplement dated February 17, 2022, the licensee provided the evaluation of the external flooding hazard risk. All external flooding hazards were screened using the screening criteria in the ASME/ANS PRA Standard ASME/ANS RA-Sa-2009. Regarding the screening of local intense precipitation (LIP) and probable maximum flood (PMF) events, the licensee concluded, based on engineering evaluation, that flood heights within safety-related structures did not affect mitigating strategy equipment and were bounded by internal flood results.

The NRC staff previously reviewed the Comanche Peak Flood Hazard Reevaluation Report (Reference 39) and the Comanche Peak Flooding Focused Evaluation Summary Report (Reference 40) with regard to the reevaluated LIP and PMF hazards developed in response to the NRC Near-Term Task Force Recommendation 2.1 for flooding dated March 12, 2012. Based on the conclusions of the NRC assessment of the reevaluated LIP and PMF hazards and potential impacts during reactor operation in the NRC staff assessment of the Commanche Peak flooding focused evaluation, dated March 26, 2018 (Reference 41), , the NRC staff's review finds that the licensee has appropriately considered the risk from external flooding in the proposed RICTs and that the external flooding hazard has an insignificant contribution to configuration risk and can be excluded from the calculation of the proposed RICTs. Furthermore, the NRC staff's review also finds that plant procedures exist to ensure that flood protection features will be available during RICTs to manage the external flooding risk in the RICT Program.

The licensee provided rationale for the insignificant impact of other external hazards for Comanche Peak, including consideration of configuration in table E4-6 of enclosure 4 to the LAR supplement dated February 17, 2022. The licensee further stated that this assessment included consideration of configuration-specific conditions. For all other external hazards, the NRC staff's review of the information in the submittal and supplement finds that the contributions from other external hazards have an insignificant contribution to configuration risk and can be excluded from the calculation of the proposed RICTs because they either do not challenge the plant or they are bounded by the external hazards analyzed for the plant. The NRC staff's review notes that the preliminary screening criteria and progressive screening criteria used and presented in table E4-5, "Screening Criterion," of enclosure 4, "Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models," to the

LAR is the same criteria presented in SRs for screening external hazards EXT-B1 and EXT-C1 of the ASME/ANS PRA Standard ASME/ANS RA-Sa-2009.

3.2.4.1.4 PRA Results and Insights

The proposed change implements a process to determine TS RICTs rather than specific changes to individual TS CTs. NEI 06-09-A delineates that periodic assessment be performed of the risk incurred due to operation beyond the “front stop” CTs resulting from implementation of the RICT Program and comparison to the guidance of RG 1.174, Revision 1, for small increases in risk. In enclosure 5, “Baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF),” to the LAR supplement, dated February 17, 2022, the licensee provided the estimated total CDF and LERF to demonstrate meeting the 1E-4/year CDF and 1E-5/year LERF criteria of RG 1.174, Revision 3, consistent with the guidance in NEI 06-09-A, and that these guidelines will be satisfied for implementation of a RICT.

Based on RG 1.174, Revision 3, and section 6.4, “Step D-3: Comparison of the Risk Results with the Application Acceptance Guidelines,” of NUREG-1855, Revision 1, for a CC-II risk evaluation, the mean values of the risk metrics (total and incremental values) need to be compared against the risk acceptance guidelines. The mean values referred to are the means of the probability distributions that result from the propagation of the uncertainties on the PRA input parameters and model uncertainties explicitly reflected in the PRA models. In general, the point estimate CDF and LERF obtained by quantification of the cutset probabilities using mean values for each basic event probability does not produce a true mean of the CDF/LERF. Under certain circumstances, a formal propagation of uncertainty may not be required if it can be demonstrated that the state of knowledge correlation (SOKC) is unimportant (i.e., the risk results are well below the acceptance guidelines).

The internal events, internal flooding, and internal fire PRA results for CDF and LERF reported in table 1, “CPNPP Units 1 and 2 Baseline PRA Model Results,” of enclosure 5 to the LAR supplement, dated February 17, 2022, are point estimate values. It is reported in this same section of the LAR supplement that accounting for SOKC in the quantification of the IEPRA increases internal events CDF and LERF by less than 5 percent. Internal flooding is a small contributor to both CDF and LERF relative to the contributions from internal events and internal fires and so accounting for SOKC in the quantification is not significant to the total CDF and LERF. Accounting for SOKC in the quantification of the internal FPRA impacts internal fire CDF and LERF by less than 1 percent for both Comanche Peak units. Based on these results, the NRC staff finds that the impact of explicitly accounting for the SOKC correlations has minimal impact on the RICT calculation because the licensee has shown that the impact on the IEPRA, internal flooding PRA, and internal FPRA is small.

In an RAI (Reference 11), the NRC staff requested the licensee to confirm that the seismic CDF and LERF values reported in table 1 of enclosure 5, “Information Supporting Consistency with Regulatory Guide 1.200, Revision 3,” to the LAR are incorrect and should be identical to the bounding seismic CDF and LERF values reported in table E4-1, “Seismic Results Summary for CPNPP,” of enclosure 4, to the LAR for use as the seismic penalty factors. In response to the RAI, the licensee confirmed the NRC staff’s understanding. The NRC staff finds that adding the seismic CDF and LERF to the total CDF and LERF results reported in table 1 of enclosure 5 to the LAR does not change the NRC staff findings and conclusions in this SE.

The licensee has incorporated NEI 06-09-A into TS 5.5.23. The current total CDF and LERF estimated using the Comanche Peak PRAs and including the penalty factors for seismic and high winds risk, and after accounting for SOKC in the quantification of the PRAs, meet the RG 1.174, Revision 3 guidelines. Therefore, the NRC staff concludes the PRA results and insights to be used by the licensee in the RICT Program will continue to be consistent with NEI 06-09-A.

3.2.4.1.5 Key Assumptions and Uncertainty Analyses

The licensee considered PRA modeling uncertainties and their potential impact on the RICT Program and identified, as necessary, the applicable RMAs to limit the impact of these uncertainties. In enclosure 9 to the LAR supplement dated February 17, 2022, the licensee discussed the identification of key assumptions and sources of uncertainty along with providing the dispositions for impact on the risk-informed application or applicable sensitivities. The licensee evaluated the Comanche Peak PRA model to identify the key assumptions and sources of uncertainty for this application, consistent with the RG 1.200, Revision 3, definitions, using sensitivity and importance analyses to place bounds on uncertain processes, to identify alternate modeling strategies, and to provide information to users of the PRA.

The NRC staff's review finds that the licensee performed an adequate assessment to identify the potential sources of uncertainty, and the identification of the key assumptions and sources of uncertainty was appropriate and consistent with the guidance in NUREG-1855 and associated EPRI TR-1016737, "Treatment of Parameter and Model Uncertainty for Probabilistic Risk Assessments," (Reference 42) and EPRI TR-1026511, "Practical Guidance of the Use of Probabilistic Risk Assessment in Risk-informed Applications with a Focus on the Treatment of Uncertainty," (Reference 43). Therefore, the NRC staff finds that the licensee has satisfied the guidance in RG 1.177, Revision 2, and RG 1.174, Revision 3, and that the identification of assumptions and treatment of model uncertainties for risk evaluation of extended CTs is appropriate for this application and consistent with the guidance identified in NEI 06-09-A.

In response to NRC Question 05 in the LAR supplement dated February 17, 2022, the license provided additional information on the dispositions to a few assumptions and sources of uncertainty: (1) the development and application of testing and maintenance (T&M) unavailabilities in the RICT PRA model, which was identified as a key assumption and source of uncertainty in table 1 of enclosure 9 to the LAR supplement dated February 17, 2022, (2) the assumption that the operator action to control AFW upon battery depletion is not a key source of uncertainty to the RICT application, and (3) the assumption that the availability of the component cooling system cross-tie between units is not a key source of uncertainty to the RICT application. Regarding the first item on T&M unavailabilities, the licensee explained that all necessary alignments are explicitly modeled and are appropriately set in the RICT Program model for calculation of configuration risk and that T&M event probabilities are set to zero in the RICT Program model in accordance with NEI 06-09-A. Because the T&M event probabilities are set to zero in the RICT Program model in accordance with NEI 06-09-A, the NRC staff finds that the development and application of T&M event probabilities for the baseline PRA model is not a key assumption or source of uncertainty for the RICT Program.

Regarding the second item on the operator action to control AFW upon battery depletion, the licensee explained that assumptions regarding this operator action can have a significant impact on CDF. However, it was further explained that this operator action is only applicable in response to a total LOF (or loss of redundant trains), which is not permitted in the RICT Program per TSTF-505, Revision. 2. Because this operator action is only ever credited in both the baseline and equipment out-of-service configurations when calculating RICTs, the NRC staff finds that the human reliability analysis assumptions made in the development of this operator action human failure event is unlikely to be significant to the RICT calculations.

Regarding the third item on the crossties of the CCW system, the licensee explained that the crossties have a significant impact on CDF. It was further explained, however, that these crossties are explicitly modeled in the RICT model so that when they are out of service, the impact is included in the RICT calculations. Because the CCW system crossties are explicitly modeled in the RICT model, the NRC staff finds that their treatment is not a key assumption or source of uncertainty for the RICT Program.

In enclosure 2 to the LAR supplement dated February 17, 2022, the licensee identifies that the Comanche Peak RCPs contain the Westinghouse low-leakage Generation III Shutdown Seals. It is further explained that the Comanche Peak PRA models include modeling of these seals in accordance with the NRC-approved version of Pressurized Water Reactor Owners Group topical report (PWROG)-14001-P-A, "PRA Model for the Generation III Westinghouse Shutdown Seal" dated October 2017 (Reference 44). The NRC SE for this topical report, dated August 23, 2017 (Reference 45), identifies limitations and conditions regarding its use in risk-informed applications. The LAR supplement states that the Comanche Peak PRA models are consistent with PWROG-14001-P-A and address all the NRC limitations and conditions. The LAR supplement specifically addresses Limitation and Condition Nos. 2 and 4. In response to NRC Question 06 in the LAR supplement dated February 17, 2022, the licensee addresses Limitation and Condition Nos. 5 and 10, including identifying two operator actions important to ensuring success of the seals: (1) timely trip of the RCPs and (2) reactor cooldown with secondary cooling (i.e., with the SGs). The licensee explains that neither of these actions are specific to LCOs included within the scope of the RICT Program and that, furthermore, these actions are only used for loss of seal failure scenarios that can only occur if there is an LOF for systems and components that are included within the RICT Program (i.e., loss of seal injection due to loss of all centrifugal charging pumps and loss of thermal barrier cooling due to loss of CCW), which is not permitted in the RICT Program per TSTF-505, Revision 2. Because these operator actions are only ever credited in both the baseline and equipment out-of-service configurations when calculating RICTs, the NRC staff finds that the associated human failure event are unlikely to be significant to the RICT calculations.

In response to NRC Question 07 in the LAR supplement dated February 17, 2022, the licensee explained that the only digital systems at Comanche Peak are associated with balance-of-plant systems that are not modeled in the PRA model. Based on this, the NRC staff finds that the RICT calculations are not impacted by the uncertainty associated with modeling of digital systems

Given the NRC staff's review of the licensee's dispositions provided in enclosure 9, "Key Assumptions and Sources of Uncertainty," to the LAR, to the identified key assumptions and sources of modeling uncertainty, and the supplemental responses provided by the licensee, the NRC staff finds the licensee's treatment of the identified key assumptions and key sources of uncertainty for this application is consistent with NUREG-1855 and NEI 06-09-A.

3.2.4.1.6 PRA Scope and Acceptability Conclusions

The licensee has subjected the PRA models to the peer review processes and submitted the results of the peer review. The NRC staff reviewed the peer review history, which included the results and findings, the licensee's resolutions of peer review findings, and the identification and disposition of key assumptions and sources of uncertainty. The NRC staff concludes that (1) the licensee's PRA models are acceptable to support the RICT Program and (2) the key assumptions for the PRAs have been identified consistent with the guidance in RG 1.200, Revision 3 and NUREG-1855. Additionally, the licensee's approach for considering the impact of seismic events, non-seismic external hazards, and other hazards using alternative methods is acceptable.

Based on the above conclusions discussed in sections 3.2.4.1.1 through 3.2.4.1.5 of this SE, the NRC staff finds that the licensee has satisfied the intent of Tier 1 in RG 1.177, Revision 2, and RG 1.174, Revision 3, for determining the PRA acceptability, and that the scope of the PRA models (i.e., IEPRA, FPRA, and the use of a bounding analysis for seismic and high winds events) is appropriate for this application.

3.2.4.1.7 Application of PRA Models in the RICT Program

The Comanche Peak base PRA models determined to be acceptable in section 3.2.4.1.6 of this SE will be modified as an application-specific PRA model (i.e., CRMP tool), that will be used to analyze the risk for an extended CT. The PRA model used in the CRMP tool produces results (i.e., risk metrics) that are consistent with the NEI 06-09-A guidance. Throughout the entirety of the LAR and associated supplements as discussed below, specifically table E1-1 of enclosure 1 to the LAR supplement dated February 17, 2022, the licensee provided all information to support the requested LCO actions proposed for the Comanche Peak RICT Program consistent with all the limitations and conditions prescribed in section 4.0, "Limitations and Conditions," of NEI 06-09-A.

In response to NRC Question 08 in the LAR supplement dated February 17, 2022, the licensee identifies and describes all credited shared systems and equipment and describes the PRA modeling for a dual unit event. Not all the shared systems or equipment are designed to provide simultaneous support to both units. In these cases, the RICT model for each unit is explicitly configured in real time to represent the unit alignment of the shared systems and equipment so that they are only credited in the PRA models for each unit consistent with the design capacities or capabilities. The NRC staff finds that the modeling of shared systems or equipment does not over-credit these systems or equipment in a dual unit event.

In table 1 of enclosure 9 to the LAR supplement dated February 17, 2022, the disposition to item No. 5 regarding key sources of modeling assumptions and uncertainties states that house events are included in the RICT Program model to specify seasonal conditions to ensure that seasonal variations are accounted for in the calculation of RICTs. An example is provided in which the house event is set to TRUE when cooling from the vent-chilled water system is required to support summer operation of Comanche Peak. In response to NRC Question 09 in the LAR supplement dated February 17, 2022, the licensee identifies two other systems in which the RICT Program model modifies the success criteria based on outside air temperatures: (1) the number of circulating water pumps required to support cooling of the turbine plant cooling water systems and (2) the number of DG ventilation fans required to maintain temperatures in the DG rooms. It is also explained that factors are applied in the RICT Program model to increase the probability of specific initiating event frequencies when an environmental change needs to be accounted for in the RICT calculations. Environmental changes include peak grid demand, severe weather, switchyard work, activities that could induce a reactor or turbine trip, activities that could induce a loss of feedwater, and activities that may cause an inadvertent safety injection signal. The NRC staff finds that the RICT Program model meets the guidance in NEI 06-09-A for ensuring that the risk impact of out-of-service equipment is appropriately evaluated because adjustments are made, as necessary, to reflect the actual seasonal and environmental conditions of the plant when quantifying RICTs.

In enclosure 7, "PRA Model Update Process," to the LAR and in the response to NRC Question ARII 1 in the LAR supplement dated July 13, 2021, the licensee explained that PRA updates for plant changes are performed at least once every 48 months. The justification for this PRA update frequency is because Comanche Peak is a dual unit facility with a common PRA for both units and an update frequency of every 48 months ensures that two 18-month refueling cycles for each unit are included (while not exceeding two refueling cycles on either unit), which are staggered by 9 months. In response to NRC Question 10 in the LAR supplement dated February 17, 2022, the licensee further justifies this update frequency by explaining that (1) the Comanche Peak Maintenance Rule Program monitors component failures and initiates corrective actions prior to the development of increasing trends in failure rates and (2) the Mitigating System Performance Index (MSPI) Program at Comanche Peak requires, on a quarterly basis, an assessment of the impact of plant changes on the PRA model and a determination of whether the changes are significant enough to warrant a model of record change. The NRC staff disagrees with the licensee's statement that the update frequency does not exceed two refueling cycles since the refueling cycle for each unit is 18 months and, therefore, one of the units is well into its third refueling cycle before the PRA is updated. However, the NRC staff finds the proposed Comanche Peak PRA model update frequency of 48 months reasonable because (1) a common PRA model is used for both Comanche Peak units, (2) the Maintenance Rule Program implemented at Comanche Peak provides assurance that component failures are addressed prior to the development of increasing trends in failure rates, and (3) the MSPI Program implemented at Comanche Peak provides assurance that plant changes that have a significant impact on plant risk, including configuration risk, require an interim PRA model/RICT model update.

In table E1-1 of enclosure 1 to the LAR supplement dated February 17, 2022, regarding TS LCO 3.4.9.B ("One required group of pressurizer heaters inoperable"), the licensee states that the pressurizer heaters are not modeled in the PRA and that, therefore, the RICT for this configuration is calculated using a surrogate. Footnote 9 to this table clarifies that the surrogate is to increase the likelihood of a plant trip due to degraded pressure control by a factor of 10. The justification for this surrogate, as explained in footnote 6 to table E1-3, "Conditions Requiring Additional Justification," of enclosure 1 to the LAR supplement dated February 17, 2022, is that the pressurizer heaters do not perform a significant accident mitigation function, are not credited for accident mitigation in the safety analyses, are not required for mitigation of SG tube rupture events, and therefore do not have a quantifiable impact on CDF or LERF. In response to NRC Question 11 in the LAR supplement dated February 17, 2022, the licensee provides additional justification for this surrogate by explaining that, because the purpose of the pressurizer heaters is to maintain pressure control during normal operations and in response to anticipated design-basis transients, the unavailability of the pressurizer heaters may slightly increase the potential for an unplanned reactor trip during significant plant transients. Based on the reactor trip frequency of 0.577 events per year used in the current PRA model of record, a factor of 10 increase in the likelihood of a reactor trip increases this frequency to 5.77 events per year. The licensee explains that this assumption is conservative because (1) it assumes that pressurizer heater control leading to a plant trip is the sole contributor to the plant trip frequency when, in fact, it is one of many contributors and (2) that the loss of a single bank of pressurizer heaters would be the singular cause leading to multiple plant trips in a year, which is not realistic because of existing Comanche Peak programs to prevent such recurrences. While the licensee’s proposed surrogate for TS LCO 3.4.9.B is unrelated to the function of the pressurizer heaters to maintain subcooled conditions in the reactor coolant system and ensure the capability to remove core decay heat by either forced or natural circulation of reactor coolant, the NRC staff finds it is acceptable and conservative for the RICT application because unavailability of a bank of pressurizer heaters (1) to perform their mitigation function in the event of a plant transient has an insignificant impact on CDF and LERF and (2) would contribute to significantly less than five reactor trips per year given existing Comanche Peak programs to prevent such recurrences.

The NRC staff did not identify any insufficiencies in the information or the CRMP tool (Real Time Risk model) as described in the LAR, as supplemented on July 13, 2021, and February 17, 2022. Furthermore, as stated in enclosure 1 to the LAR supplement dated July 13, 2021, the Comanche Peak design criteria are not changed by the LAR, as supplemented. The NRC staff finds that the Comanche Peak PRA models and CRMP tool used will continue to reflect the as-built, as-operated plant consistent with RG 1.200, Revision 3, for ensuring PRA acceptability is maintained. Therefore, the NRC staff concludes that the proposed application of the Comanche Peak RICT Program is appropriate for use in the adoption of TSTF-505 for performing RICT calculations.

3.2.4.2 Tier 2: Avoidance of Risk-Significant Plant Configurations

As prescribed in RG 1.177, Revision 2, the second tier evaluates the capability of the licensee to recognize and avoid risk-significant plant configurations that could result if equipment, in addition to that associated with the proposed change, is taken out of service simultaneously, or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. The limits established for entry into a RICT and for RMA implementation are consistent with the guidance of NUMARC 93-01, Revision 4F, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” dated April 2018 (Reference 46), endorsed by RG 1.160, Revision 4, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” dated August 2018 (Reference 47), as applicable to plant maintenance activities. The RICT Program requirements and criteria are consistent with the principle of Tier 2 to avoid risk-significant configurations.

Consistent with NEI 06-09-A, LAR enclosure 12 identifies three kinds of RMAs (i.e., actions to provide increased risk awareness and control, actions to reduce the duration of maintenance activities, and actions to minimize the magnitude of the risk increase). In the LAR, the licensee also explained that RMAs will be implemented, in accordance with current plant procedures, no later than the time at which the incremental core damage probability of 1E-06 or the incremental large early release probability of 1E-07 threshold is reached and under emergent conditions when the instantaneous CDF and LERF thresholds are exceeded. RMAs will also be implemented under emergent conditions, if the extent of condition is not known prior to exceeding the CT, to account for the increased possibility of CCF.

Based on the licensee's incorporation of NEI 06-09-A in the TSs as discussed in LAR attachment 1, "Description and Assessment of the Proposed Changes," use of RMAs as discussed in LAR enclosure 12, and because the proposed changes are consistent with the Tier 2 guidance of RG 1.177, Revision 1, the NRC staff finds the licensee's Tier 2 program is acceptable and supports the proposed implementation of the RICT Program.

3.2.4.3 Tier 3: Risk-Informed Configuration Risk Management

The Tier 3 requirement of RG 1.177, Revision 2, stipulates that a licensee should develop a program that ensures that the risk impact of out-of-service equipment is appropriately evaluated prior to performing any maintenance activity.

The proposed RICT Program establishes a Real Time Risk model based on the underlying PRA models. In enclosure 8, "Attributes of the Real-Time Risk Model," to the LAR, the licensee explained the adjustments to PRA models (e.g., adjustments to maintenance unavailability) to ensure its proper use of models in the RTR model calculations. The RTR model is then used to evaluate configuration-specific risk for planned activities associated with the RMTS extended CT, as well as emergent conditions, which may arise during an extended CT. This required assessment of configuration risk, along with the implementation of compensatory measures and RMAs, is consistent with the principle of Tier 3 for assessing and managing the risk impact of out-of-service equipment.

In LAR enclosure 8, the licensee confirms that future changes made to the baseline PRA models and changes made to the online model (i.e., RTR) are controlled and documented by plant procedures. In LAR enclosure 10, "Program Implementation," the licensee identified the attributes that the RICT Program procedures will address, which are consistent with NEI 06-09-A.

The NRC staff reviewed the description of the training program provided in the LAR, and concluded that the program is consistent with the training requirements set forth in NEI 06-09-A. Therefore, the NRC staff finds that the licensee has proposed acceptable administrative controls for the PRA and personnel implementing the RICT Program and will establish appropriate programmatic and procedural controls for its RICT Program, consistent with the guidance of NEI 06-09-A, section 3.2.1, "RMTS Process Control and Responsibilities."

Based on the licensee's incorporation of NEI 06-09-A in the TS, as discussed in LAR attachment 1, use of RMAs as discussed in LAR enclosure 12, and because the proposed changes are consistent with the Tier 3 guidance of RG 1.177, Revision 2, the NRC staff finds the licensee's Tier 3 program is acceptable and supports the proposed implementation of the RICT Program.

3.2.4.4 Key Principle 4 Conclusions

The licensee has demonstrated the technical acceptability and scope of its PRA models and alternative methods. This includes considering the impact of seismic events, extreme winds and tornado hazards, and other external hazards, and that the models can support implementation of the RICT Program for determining extensions to CTs. The licensee has made proper consideration of key assumptions and sources of uncertainty. The risk metrics are consistent with the approved methodology of NEI 06-09-A and the acceptance guidance in RG 1.177, Revision 2, and RG 1.174, Revision 3. The RICT Program will be controlled administratively through plant procedures and training and follows the NRC-approved methodology in

NEI 06-09-A. The NRC staff concludes that the RICT Program satisfies the fourth key principle of RG 1.177, Revision 2, and is, therefore, acceptable.

3.2.5 Key Principle 5: Performance Measurement Strategies – Implementation and Monitoring

The guidance in RG 1.177, Revision 2, and RG 1.174, Revision 3, establishes the need for an implementation and monitoring program to ensure that extensions to TS CTs do not degrade operational safety over time and that no adverse degradation occurs due to unanticipated degradation or common cause mechanisms. An implementation and monitoring program is intended to ensure that the impact of the proposed TS change continues to reflect the availability of SSCs impacted by the change. The guidance in RG 1.174, Revision 3 states, in part, that monitoring performed in conformance with the Maintenance Rule (10 CFR 50.65), can be used when the monitoring performed is sufficient for the SSCs affected by the risk-informed application. In enclosure 11, “Monitoring Program,” to the LAR supplement dated February 17, 2022, the license stated that the SSCs in the scope of the RICT Program are also in the scope of 10 CFR 50.65 for the Maintenance Rule. The Maintenance Rule monitoring programs will provide for evaluation and disposition of unavailability impacts, which may be incurred from implementation of the RICT Program. In enclosure 11 and the response to NRC Question 12 in the LAR supplement dated February 17, 2022, the licensee described the approach and methods used for SSC performance monitoring as described in Regulatory Position C.3.2 of RG 1.177, Revision 2, for meeting the fifth key principle of risk-informed decision-making.

In the response to NRC Question 13 in the LAR supplement dated February 17, 2022, the licensee stated that cumulative risk from the use of the RICT Program will be continuously tracked for each of the Comanche Peak units for a rolling 12-month period for comparison against the RG 1.174, Revision 3, risk guidelines. In addition, in enclosure 11 to the LAR supplement dated February 17, 2022, the licensee stated that the cumulative risk impact is calculated at least once every 48 months as part of the periodic review and update of the PRA models. The NRC staff finds that licensee’s proposed periodicity of tracking cumulative risk on a rolling 12-month period is consistent with the guidance in NEI 06-09-A, section 2.3.1, “Configuration Risk Management Process & Application of Technical Specifications.”

The NRC staff concludes that the RICT Program satisfies the fifth key principle of RG 1.177, Revision 2, and RG 1.174, Revision 3, because: (1) the RICT Program will monitor the average annual cumulative risk increase as described in NEI 06-09-A, and use this average annual increase to ensure the program, as implemented, meets RG 1.174 guidance for small risk increases; and (2) all affected SSCs are within the Maintenance Rule program, which is used to monitor changes to the reliability and availability of these SSCs.

3.3 Variations from TSTF-505

The NRC staff evaluated the proposed use of RICTs in the optional changes and variations stated in sections 2.1.4.1 and 2.1.4.2 of this SE, in conjunction with evaluating the proposed use of RICTs in each of the individual LCOs, required actions, and CTs as stated in section 2.1.3 of this SE. The NRC staff’s evaluation of the licensee’s proposed use of RICTs in the variations against the key safety principles is discussed in sections 3.2.1 through 3.2.5 of this SE. Based on sections 3.2.1 through 3.2.5 of this SE, the NRC staff finds that each of the five key principles in RG 1.177, Revision 2, and RG 1.174, Revision 3, have been met and concludes that the proposed optional changes and variations are acceptable.

The NRC staff reviewed the proposed TS changes in section 2.1.4.3 of this SE and found that they are non-technical and editorial in nature. The changes will simplify the requirements and improve consistency within the TS. Therefore, NRC staff finds these changes acceptable.

3.4 TS Administrative Controls Section

The NRC staff reviewed the licensee's proposed addition of the RICT Program to the Administrative Controls section of the TS. The NRC staff evaluated the elements of the new program to ensure alignment with the requirements in 10 CFR 50.36(c)(5) and to ensure the programmatic controls are consistent with the RICT Program described in NEI 06-09-A.

The regulations in 10 CFR 50.36(c)(5) require the TS to contain administrative controls providing "provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner." The NRC staff has determined that the Administrative Controls section of the TS will assure the licensee's RICT Program will be implemented consistent with the elements prescribed in NEI 06-09-A. Therefore, the NRC staff has determined that the requirements of 10 CFR 50.36(c)(5) are satisfied.

3.5 Technical Evaluation Conclusion

The NRC staff has evaluated the proposed changes against each of the five key principles in RG 1.177, Revision 2, and RG 1.174, Revision 3. The NRC staff concludes that the proposed changes satisfy the key principles of risk-informed decision-making identified in RG 1.174, and RG 1.177 and, therefore, the requested adoption of the proposed changes to the TSs is acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Texas State official was notified of the proposed issuance of the amendments on July 8, 2022. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration published in the *Federal Register* on September 7, 2021 (86 FR 50195), and there has been no public comment on such finding. Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

6.0 CONCLUSION

Based on the considerations discussed above, the NRC staff concludes that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) there is reasonable assurance that such activities will be conducted in compliance with the Commission’s regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

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Date: August 22, 2022

SUBJECT: COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 183 AND 183 REGARDING THE ADOPTION OF TECHNICAL SPECIFICATIONS TASK FORCE TRAVELER TSTF-505, REVISION 2 (EPID L-2021-LLA-0085) DATED AUGUST 22, 2022

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