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

June 28, 2021

Mr. David P. Rhoades
Senior Vice President
Exelon Generation Company, LLC
President and Chief Nuclear Officer (CNO)
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: CLINTON POWER STATION, UNIT NO. 1 - ISSUANCE OF AMENDMENT NO. 238 RE: TECHNICAL SPECIFICATIONS TASK FORCE TRAVELER TSTF-505, REVISION 2, "PROVIDE RISK-INFORMED EXTENDED COMPLETION TIMES – RITSTF INITIATIVE 4B" (EPID L-2020-LLA-0097)

Dear Mr. Rhoades:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 238 to Facility Operating License No. NPF-62 for the Clinton Power Station, Unit No. 1. The amendment is in response to your application dated April 30, 2020 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML20121A178) as supplemented by letters dated November 24, 2020 (ADAMS Accession No. ML20329A433) and March 23, 2021 (ADAMS Accession No. ML21082A268).

The amendment modifies technical specifications 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 Initiative 4b," (ADAMS Accession No. ML18183A493).

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

Sincerely,

/RA/

Joel S. Wiebe, Senior Project Manager
Plant Licensing Branch III
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-461

Enclosures:
1. Amendment No. 238 to NPF-62
2. Safety Evaluation

cc: Listserv

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-461

CLINTON POWER STATION, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 238
License No. NPF-62

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

   A. The application for amendment by Exelon Generation Company, LLC (the licensee), dated April 30, 2020, as supplemented by letters dated November 24, 2020 and March 23, 2021, 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 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-62 is hereby amended to read as follows:

    (2) Technical Specifications and Environmental Protection Plan

    The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 238, are hereby incorporated in the license. Exelon Generation Company 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 of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Nancy L. Salgado

Digitally signed by Nancy L. Salgado
Date: 2021.06.28 14:54:11 -04'00'

Nancy L. Salgado, Chief
Plant Licensing Branch III
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility Operating License and Technical Specifications

Date of Issuance: June 28, 2021

ATTACHMENT TO LICENSE AMENDMENT NO. 238

FACILITY OPERATING LICENSE NO. NPF-62

CLINTON POWER STATION, UNIT NO. 1

DOCKET NO. 50-461

Replace the following pages of the Facility Operating License No. NPF-62 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.

REMOVE	INSERT
Page 3	Page 3

Technical Specifications

REMOVE	INSERT
1.0-24	1.0-24
1.0-25	1.0-25
1.0-26	1.0-26
1.0-27	1.0-27
1.0-28	1.0-28
1.0-29	1.0-29
--	1.0-30
3.1-20	3.1-20
3.3-1	3.3-1
3.3-2	3.3-2
3.3-25	3.3-25
3.3-26	3.3-26
3.3-32	3.3-32
3.3-33	3.3-33
3.3-34	3.3-34
3.3-35	3.3-35
3.3-36	3.3-36
3.3-37	3.3-37
--	3.3-37a
--	3.3-37b
3.3-45	3.3-45
3.3-46	3.3-46
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
3.3-65	3.3-65
3.3-66	3.3-66

REMOVE (continued)	INSERT (continued)
3.3-69	3.3-69
3.3-70	3.3-70
3.3-74	3.3-74
3.3-78	3.3-78
3.3-79	3.3-79
3.3-80	3.3-80
3.3-81	3.3-81
3.3-82	3.3-82
--	3.3-83
3.5-1	3.5-1
3.5-2	3.5-2
3.5-3	3.5-3
3.5-4	3.5-4
3.5-5	3.5-5
3.5-6	3.5-6
3.5-7	3.5-7
3.5-8	3.5-8
3.5-9	3.5-9
3.5-10	3.5-10
3.5-11	3.5-11
3.5-12	3.5-12
--	3.5-13
--	3.5-14
3.6-6	3.6-6
3.6-10	3.6-10
3.6-11	3.6-11
3.6-13	3.6-13
3.6-14	3.6-14
3.6-22	3.6-22
3.6-24	3.6-24
3.6-32	3.6-32
3.6-34	3.6-34
3.6-59	3.6-59
3.6-62	3.6-62
3.7-1	3.7-1
3.7-13	3.7-13
3.7-14	3.7-14
3.8-1	3.8-1
3.8-2	3.8-2
3.8-3	3.8-3
3.8-4	3.8-4
3.8-5	3.8-5
3.8-6	3.8-6
3.8-6a	--
3.8-6b	--
3.8-7	3.8-7
3.8-24	3.8-24
3.8-24a	3.8-24a
3.8-34	3.8-34
3.8-35	3.8-35

REMOVE (continued)	INSERT (continued)
3.8-39	3.8-39
3.8-40	3.8-40
3.8-41	3.8-41
5.0-16c	5.0-16c
5.0-17	5.0-17
5.0-18	5.0-18
5.0-19	5.0-19

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

(6) Exelon Generation Company, 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. Mechanical disassembly of the GE14i isotope test assemblies containing Cobalt-60 is not considered separation; and

(7) Exelon Generation Company, pursuant to the Act and 10 CFR Parts 30, to intentionally produce, possess, receive, transfer, and use Cobalt-60.

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

Exelon Generation Company is authorized to operate the facility at reactor core power levels not in excess of 3473 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 238, are hereby incorporated into this license. Exelon Generation Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-7 (continued)

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.

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.

(continued)

1.3 Completion Times

EXAMPLES	<u>EXAMPLE 1.3-8</u> (continued) 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, Condition 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.

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated Limiting Condition for Operation (LCO). An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR, as well as certain Notes in the Surveillance column that modify performance requirements.

Sometimes special situations dictate when the requirements of a Surveillance are to be met. They are "otherwise stated" conditions allowed by SR 3.0.1. They may be stated as clarifying Notes in the Surveillance, as part of the Surveillance, or both. Example 1.4-4 discusses these special situations.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

The use of "met" or "performed" in these instances conveys specified meanings. A Surveillance is "met" only when the acceptance criteria are satisfied. Known failure of the requirements of a Surveillance, even without a Surveillance specifically being "performed," constitutes a Surveillance not "met." "Performance" refers only to the requirement to specifically determine the ability to meet the acceptance

(continued)

1.4 Frequency

DESCRIPTION (continued)

criteria. SR 3.0.4 restrictions would not apply if both the following conditions are satisfied:

a. The Surveillance is not required to be performed; and

b. The Surveillance is not required to be met or, even if required to be met, is not known to be failed.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3. The examples do not reflect the potential application of LCO 3.0.4.b.

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the interval specified in the Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Examples 1.4-3 and 1.4-4), then SR 3.0.3 becomes applicable.

(continued)

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-1 (continued)

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, the Surveillance must be performed within the Frequency requirements of SR 3.0.2 prior to entry into the MODE or other specified condition. Failure to do so would result in a violation of SR 3.0.4.

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the extension allowed by SR 3.0.2.

(continued)

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-2 (continued)

"Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

EXAMPLE 1.4-3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-------------------NOTE------------------- Not required to be performed until 12 hours after ≥ 25% RTP. --- Perform channel adjustment.	7 days

The interval continues whether or not the unit operation is < 25% RTP between performances.

As the Note modifies the required performance of the Surveillance, it is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is < 25% RTP, this Note allows 12 hours after power reaches ≥ 25% RTP to perform the Surveillance. The Surveillance is still considered to be within the "specified Frequency." Therefore, if the Surveillance were not performed within the 7 day interval (plus the extension allowed by SR 3.0.2), but operation was < 25% RTP, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not exceed 12 hours (plus the extension allowed by SR 3.0.2) with power ≥ 25% RTP.

(continued)

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-3 (continued)

Once the unit reaches 25% RTP, 12 hours would be allowed for completing the Surveillance. If the Surveillance were not performed within this 12 hour interval (plus the extension allowed by SR 3.0.2), there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

EXAMPLE 1.4-4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-------------------NOTE------------------ Only required to be met in MODE 1. -- Verify leakage rates are within limits.	24 hours

Example 1.4-4 specifies that the requirements of this Surveillance do not have to be met until the unit is in MODE 1. The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour (plus the extension allowed by SR 3.0.2) interval, but the unit was not in MODE 1, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES, even with the 24 hour Frequency exceeded, provided the MODE change was not made into MODE 1. Prior to entering MODE 1 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One SLC subsystem inoperable.	A.1 Restore SLC subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Two SLC subsystems inoperable.	B.1 Restore one SLC subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify available volume of sodium pentaborate solution is within the limits of Figure 3.1.7-1.	In accordance with the Surveillance Frequency Control Program

(continued)

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

-------------------------------------NOTES-------------------------------------

1. Separate Condition entry is allowed for each Function.

2. When Functions 2.b and 2.c channels are inoperable due to the calculated power exceeding the APRM output by more than 2% RTP while operating at ≥ 21.6% RTP, entry into associated Conditions and Required Actions may be delayed for up to 2 hours.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel inoperable.	A.1 Place one channel in affected Function in trip.	48 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. One or more Functions with two channels inoperable.	B.1 Place one channel in affected Function in trip.	6 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. One or more Functions with three or more channels inoperable.	C.1 Restore two channels in affected Function to OPERABLE status.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1 Reduce THERMAL POWER to < 33.3% RTP.	8 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1 Reduce THERMAL POWER to < 21.6% RTP.	8 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1 Be in MODE 2.	8 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1 Be in MODE 3.	12 hours
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

3.3 INSTRUMENTATION

3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

LCO 3.3.4.1 Four channels for each EOC-RPT instrumentation Function listed below shall be OPERABLE:

a. Turbine Stop Valve (TSV) Closure; and

b. Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure-Low.

APPLICABILITY: THERMAL POWER ≥ 33.3% RTP with any recirculation pump in fast speed.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore channel to OPERABLE status.	48 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>OR</u>	
	A.2 --------NOTE--------- Not applicable if inoperable channel is the result of an inoperable breaker. --------------------- Place one channel in affected Function in trip.	48 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more Functions with two channels inoperable.	B.1 Place one channel in affected Function in trip.	6 hours OR In accordance with the Risk Informed Completion Time Program
C. One or more Functions with three or more channels inoperable.	C.1 Restore two channels in affected Function to OPERABLE status.	2 hours
D. Required Action and associated Completion Time not met.	D.1 Remove the associated recirculation pump fast speed breaker from service.	8 hours
	OR	
	D.2 Reduce THERMAL POWER to < 33.3% RTP.	8 hours

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains EOC-RPT trip capability.

SURVEILLANCE	FREQUENCY
SR 3.3.4.1.1 Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	B.1	--------NOTE--------- Only applicable for Functions 1.a, 1.b, 2.a, and 2.b. --------------------- Declare supported feature(s) inoperable when its redundant feature ECCS initiation capability is inoperable.	1 hour from discovery of loss of initiation capability for feature(s) in both divisions
	<u>AND</u>		
	B.2	--------NOTE--------- Only applicable for Functions 3.a and 3.b. --------------------- Declare High Pressure Core Spray (HPCS) System inoperable.	1 hour from discovery of loss of HPCS initiation capability
	<u>AND</u>		
	B.3	Place channel in trip.	24 hours <u>OR</u> ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	C.1 ---------NOTE-------- Only applicable for Functions 1.c, 1.d, 2.c, and 2.d. ---------------------	
	Declare supported feature(s) inoperable when its redundant feature ECCS initiation capability is inoperable.	1 hour from discovery of loss of initiation capability for feature(s) in both divisions
	<u>AND</u>	
	C.2 Restore channel to OPERABLE status.	24 hours <u>OR</u> ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	D.1 --------NOTE-------- Only applicable if HPCS pump suction is not aligned to the suppression pool. --------------------- Declare HPCS System inoperable.	1 hour from discovery of loss of HPCS initiation capability
	AND	
	D.2.1 Place channel in trip.	24 hour OR ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program
	OR	
	D.2.2 Align the HPCS pump suction to the suppression pool.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	E.1 --------NOTE--------- Only applicable for Functions 1.e, 1.f, and 2.e. --------------------- Declare supported feature(s) inoperable when its redundant feature ECCS initiation capability is inoperable.	1 hour from discovery of loss of initiation capability for feature(s) in both divisions
	AND	
	E.2 Restore channel to OPERABLE status.	7 days OR ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	F.1 Declare Automatic Depressurization System (ADS) valves inoperable.	1 hour from discovery of loss of ADS initiation capability in both trip systems
	AND	
	F.2 Place channel in trip.	96 hours or in accordance with the Risk Informed Completion Time Program from discovery of inoperable channel concurrent with HPCS or reactor core isolation cooling (RCIC) inoperable AND ------NOTE----- The Risk Informed Completion Time Program is not applicable when trip capability is not maintained. --------------- 8 days or in accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
G. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	G.1	--------NOTES-------- Only applicable for Functions 4.c, 4.e, 4.f, 4.g, 5.c, 5.e, and 5.f. ---------------------	
		Declare ADS valves inoperable.	1 hour from discovery of loss of ADS initiation capability in both trip systems
	AND		
	G.2	Restore channel to OPERABLE status.	96 hours or in accordance with the Risk Informed Completion Time Program from discovery of inoperable channel concurrent with HPCS or RCIC inoperable AND ------NOTE----- The Risk Informed Completion Time Program is not applicable when trip capability is not maintained. --------------- 8 days or in accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Required Action and associated Completion Time of Condition B, C, D, E, F, or G not met.	H.1 Declare associated supported feature(s) inoperable.	Immediately

This page intentionally left blank.

3.3 INSTRUMENTATION

3.3.5.3 Reactor Core Isolation Cooling (RCIC) System Instrumentation

LCO 3.3.5.3 The RCIC System instrumentation for each Function in Table 3.3.5.3-1 shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 with reactor steam dome pressure > 150 psig.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.5.3-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	B.1 Declare RCIC System inoperable. AND B.2 Place channel in trip.	1 hour from discovery of loss of RCIC initiation capability 24 hours OR ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	C.1 Restore channel to OPERABLE status.	24 hours
D. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	D.1 ---------NOTE---------- Only applicable if RCIC pump suction is not aligned to the suppression pool. --------------------- Declare RCIC System inoperable.	1 hour from discovery of loss of RCIC initiation capability
	AND	
	D.2.1 Place channel in trip.	24 hours OR ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program
	OR	
	D.2.2 Align RCIC pump suction to the suppression pool.	24 hours
E. Required Action and associated Completion Time of Condition B, C, or D not met.	E.1 Declare RCIC System inoperable.	Immediately

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment and Drywell Isolation Instrumentation

LCO 3.3.6.1 The primary containment and drywell isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
-----------NOTE---------- Only applicable to Main Steam Line (MSL) isolation Functions. ------------------------- A. One or more Functions with one channel inoperable.	A.1	Place one channel in affected Function in trip.	48 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
-----------NOTE---------- Only applicable to MSL isolation Functions. ------------------------- B. One or more Functions with two channels inoperable.	B.1	Place one channel in affected Function in trip.	6 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
-----------NOTE---------- Only applicable to MSL isolation Functions. ------------------------- C. One or more Functions with three or more channels inoperable.	C.1	Restore two channels in affected Function to OPERABLE status.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
------------NOTE---------- Not applicable to MSL isolation Functions. -------------------------- D. One or more required channels inoperable.	D.1 Place channel in trip.	24 hours OR ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program
------------NOTE--------- Not applicable to MSL isolation Functions. ------------------------- E. One or more automatic Functions with isolation capability not maintained.	E.1 Restore isolation capability.	1 hour
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met.	F.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately
G. As required by Required Action F.1 and referenced in Table 3.3.6.1-1.	G.1 Isolate associated MSL. OR G.2.1 Be in MODE 3. AND G.2.2 Be in MODE 4.	12 hours 12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. As required by Required Action F.1 and referenced in Table 3.3.6.1-1.	H.1 Be in MODE 2.	6 hours
I. As required by Required Action F.1 and referenced in Table 3.3.6.1-1.	I.1 Isolate the affected penetration flow path(s).	1 hour
J. As required by Required Action F.1 and referenced in Table 3.3.6.1-1.	J.1 Isolate the affected penetration flow path(s).	24 hours
K. As required by Required Action F.1 and referenced in Table 3.3.6.1-1. OR Required Action and associated Completion Time of Condition I or J not met.	K.1 Be in MODE 3. AND K.2 Be in MODE 4.	12 hours 36 hours
L. As required by Required Action F.1 and referenced in Table 3.3.6.1-1.	L.1 Declare associated standby liquid control subsystem inoperable. OR L.2 Isolate the Reactor Water Cleanup System.	1 hour 1 hour
M. As required by Required Action F.1 and referenced in Table 3.3.6.1-1.	M.1 Initiate action to restore channel to OPERABLE status. OR	Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
M. (continued)	M.2	Initiate action to isolate the Residual Heat Removal (RHR) Shutdown Cooling System suction from the reactor vessel.	Immediately
	OR		
	M.3.1	Initiate action to restore secondary containment to OPERABLE status.	Immediately
	AND		
	M.3.2	Initiate action to restore one standby gas treatment (SGT) subsystem to OPERABLE status.	Immediately
	AND		
	M.3.3	Initiate action to restore isolation capability in each required secondary containment and secondary containment bypass penetration flow path not isolated.	Immediately
	AND		
	M.3.4	---------NOTE------- Entry and exit is permissible under administrative control. --------------------	
		Initiate action to close one door in the upper containment personnel air lock.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
N. As required by Required Action F.1 and referenced in Table 3.3.6.1-1.	N.1	Isolate the affected penetration flow path(s).	Immediately
	OR		
	N.2	Suspend movement of recently irradiated fuel assemblies in the primary and secondary containment.	Immediately

SURVEILLANCE REQUIREMENTS

-------------------------------------NOTES-------------------------------------

1. Refer to Table 3.3.6.1-1 to determine which SRs apply for each Primary Containment and Drywell Isolation Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains isolation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.3	Calibrate the analog trip module.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.5	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.7	---------------NOTE--------------------- Channel sensors are excluded. -- Verify the ISOLATION SYSTEM RESPONSE TIME for the main steam isolation valves is within limits.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.8	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.6.3 Residual Heat Removal (RHR) Containment Spray System Instrumentation

LCO 3.3.6.3 The RHR Containment Spray System instrumentation for each Function in Table 3.3.6.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.6.3-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.6.3-1.	B.1 Declare associated RHR containment spray subsystem inoperable.	1 hour from discovery of loss of RHR containment spray initiation capability in both trip systems
	<u>AND</u>	
	B.2 Place channel in trip.	24 hours <u>OR</u> ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action A.1 and referenced in Table 3.3.6.3-1.	C.1 --------NOTE--------- Only applicable for Functions 4 and 5. ---------------------	
	Declare associated RHR containment spray subsystem inoperable.	1 hour from discovery of loss of RHR containment spray initiation capability in both trip systems
	<u>AND</u>	
	C.2 Restore channel to OPERABLE status.	24 hours <u>OR</u> ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time of Condition B or C not met.	D.1 Declare associated RHR containment spray subsystem inoperable.	Immediately

3.3 INSTRUMENTATION

3.3.6.4 Suppression Pool Makeup (SPMU) System Instrumentation

LCO 3.3.6.4 The SPMU System instrumentation for each Function in Table 3.3.6.4-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.6.4-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.6.4-1.	B.1 Declare associated SPMU subsystem inoperable. AND B.2 Place channel in trip.	1 hour from discovery of loss of SPMU initiation capability in both trip systems 24 hours OR ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action A.1 and referenced in Table 3.3.6.4-1.	C.1 --------NOTE--------- Only applicable for Function 4. ---------------------- Declare associated SPMU subsystem inoperable.	1 hour from discovery of loss of SPMU initiation capability in both trip systems
	AND	
	C.2 Restore channel to OPERABLE status.	24 hours OR ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time of Condition B or C not met.	D.1 Declare associated SPMU subsystem inoperable.	Immediately

3.3 INSTRUMENTATION

3.3.6.5 Relief and Low-Low Set (LLS) Instrumentation

LCO 3.3.6.5 Two relief and LLS instrumentation trip systems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One trip system inoperable.	A.1 Restore trip system to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
	OR	
	A.2 Declare associated relief and LLS valve(s) inoperable.	7 days
B. Required Action and associated Completion Time of Condition A not met. OR Two trip systems inoperable.	B.1 Be in MODE 3.	12 hours
	AND	
	B.2 Be in MODE 4.	36 hours

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When the associated diesel generator (DG) is required to be OPERABLE by LCO 3.8.2, "AC Sources–Shutdown."

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Place channel in trip. AND	1 hour OR ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 ---------NOTE---------- Only applicable for Functions 1.c, 1.d, 1.e, 2.c, 2.d, and 2.e ----------------------- Restore channel to OPERABLE status.	7 days <u>OR</u> ------NOTE----- Not applicable when trip capability is not maintained. --------------- In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTES------------------------------------

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains DG initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Deleted	
SR 3.3.8.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER DIVISION	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Divisions 1 and 2 - 4.16 kV Emergency Bus Undervoltage			
a. Loss of Voltage - 4.16 kV basis	6	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2345 V and ≤ 3395 V
b. Loss of Voltage - Time Delay	6	SR 3.3.8.1.3 SR 3.3.8.1.4	≤ 5.0 seconds
c. Degraded Voltage Reset - 4.16 kV basis	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 4102.2 V and ≤ 4109.3 V
d. Degraded Voltage Drop-out - 4.16 kV basis	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 4051 V
e. Degraded Voltage-Time Delay	1	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 14 seconds and ≤ 16 seconds
2. Division 3 - 4.16 kV Emergency Bus Undervoltage			
a. Loss of Voltage - 4.16 kV basis	4	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2345 V and ≤ 2730 V
b. Loss of Voltage - Time Delay	1	SR 3.3.8.1.3 SR 3.3.8.1.4	≤ 3.0 seconds
c. Degraded Voltage Reset - 4.16 kV basis	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 4102.2 V and ≤ 4109.3 V
d. Degraded Voltage Drop-out - 4.16 kV basis	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 4051 V
e. Degraded Voltage - Time Delay	1	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 13.2 seconds and ≤ 16.8 seconds

3.3 INSTRUMENTATION

3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

LCO 3.3.8.2 One RPS electric power monitoring assembly shall be OPERABLE for each inservice RPS special solenoid power supply or alternate power supply.

APPLICABILITY: MODES 1, 2, and 3,
MODES 4 and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both inservice power supplies with the electric power monitoring assembly inoperable.	A.1 Remove associated inservice power supply(s) from service.	1 hour
B. Required Action and associated Completion Time of Condition A not met in MODE 1, 2, or 3.	-------------NOTE------------ LCO 3.0.4a is not applicable when entering MODE 3 ------------------------------ B.1 Be in MODE 3.	 12 hours
C. Required Action and associated Completion Time of Condition A not met in MODE 4 or 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	C.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.1	------------------NOTE------------------ Only required to be performed prior to entering MODE 2 or 3 from MODE 4, when in MODE 4 for ≥ 24 hours. -- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.2.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Overvoltage Bus A ≤ 127.3 V Bus B ≤ 126.7 V b. Undervoltage Bus A ≥ 115.0 V Bus B ≥ 114.7 V c. Underfrequency (with time delay ≤ 4.0 seconds) Bus A ≥ 57 Hz Bus B ≥ 57 Hz	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.2.3	Perform a system functional test.	In accordance with the Surveillance Frequency Control Program

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.1 ECCS — Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of seven safety/relief valves shall be OPERABLE.

---------------------------NOTE---------------------------
One low pressure coolant injection (LPCI) subsystem may be inoperable during alignment and operation for decay heat removal with reactor steam dome pressure less than the residual heat removal cut in permissive pressure.

APPLICABILITY: MODE 1,
MODES 2 and 3, except ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig.

ACTIONS

-----------------------------------NOTE-----------------------------------
LCO 3.0.4.b is not applicable to High Pressure Core Spray (HPCS).

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. HPCS System inoperable.	B.1 Verify by administrative means RCIC System is OPERABLE when RCIC is required to be OPERABLE. AND B.2 Restore HPCS System to OPERABLE status.	1 hour 14 days OR In accordance with the Risk Informed Completion Time Program
C. Two ECCS injection subsystems inoperable. OR One ECCS injection and one ECCS spray subsystem inoperable.	C.1 Restore one ECCS injection/spray subsystem 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.	-------------NOTE------------ LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------- D.1 Be in MODE 3.	 12 hours
E. One ADS valve inoperable.	E.1 Restore ADS valve to OPERABLE status.	14 days OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. One ADS valve inoperable. AND One low pressure ECCS injection/spray subsystem inoperable.	F.1	Restore ADS valve to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
	OR		
	F.2	Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
G. Two or more ADS valves inoperable. OR Required Action and associated Completion Time of Condition E or F not met.	-------------NOTE------------ LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------		
	G.1	Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. HPCS and Low Pressure Core Spray (LPCS) Systems inoperable. OR Three or more ECCS injection/spray subsystems inoperable. OR HPCS System and one or more ADS valves inoperable. OR Two or more ECCS injection/spray subsystems and one or more ADS valves inoperable.	H.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify, for each ECCS injection/spray subsystem, locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.2	-------------------NOTE------------------- Not required to be met for system vent flow paths opened under administrative control. --- Verify each ECCS injection/spray subsystem 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 3.5.1.3	Verify ADS accumulator supply pressure is ≥ 140 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.4	Verify each ECCS pump develops the specified flow rate with the specified pump differential pressure. SYSTEM / FLOW RATE / PUMP DIFFERENTIAL PRESSURE LPCS / ≥ 5010 gpm / ≥ 290 psid LPCI / ≥ 5050 gpm / ≥ 113 psid HPCS / ≥ 5010 gpm / ≥ 363 psid	In accordance with the INSERVICE TESTING PROGRAM

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.5	-------------------NOTE------------------- Vessel injection/spray may be excluded. -- Verify each ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.6	-------------------NOTE------------------- Valve actuation may be excluded. -- Verify the ADS actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.7	-------------------NOTE------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. -- Verify each ADS valve actuator strokes when manually actuated.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.8	-------------------NOTE------------------- ECCS actuation instrumentation is excluded. -- Verify the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is within limits.	In accordance with the Surveillance Frequency Control Program

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.2 RPV Water Inventory Control

LCO 3.5.2 DRAIN TIME of RPV water inventory to the top of active fuel (TAF) shall be ≥ 36 hours.

AND

One ECCS injection/spray subsystem shall be OPERABLE.

-----------------------------NOTE-----------------------------
One low pressure coolant injection (LPCI) subsystem may be inoperable during alignment and operation for decay heat removal with reactor steam dome pressure less than the residual heat removal cut in permissive pressure.

APPLICABILITY: MODES 4 and 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required ECCS injection/spray subsystem inoperable.	A.1 Restore required ECCS injection/spray subsystem to OPERABLE status.	4 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action to establish a method of water injection capable of operating without offsite electrical power.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. DRAIN TIME < 36 hours and ≥ 8 hours.	C.1 Verify secondary containment boundary is capable of being established in less than the DRAIN TIME.	4 hours
	<u>AND</u>	
	C.2 Verify each secondary containment penetration flow path is capable of being isolated in less than the DRAIN TIME.	4 hours
	<u>AND</u>	
	C.3 Verify one standby gas treatment (SGT) subsystem is capable of being placed in operation in less than the DRAIN TIME.	4 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. DRAIN TIME < 8 hours.	D.1	------- NOTE -------- Required ECCS injection/spray subsystem or additional method of water injection shall be capable of operating without offsite electrical power. ---------------------	
		Initiate action to establish an additional method of water injection with water sources capable of maintaining RPV water level > TAF for ≥ 36 hours.	Immediately
	<u>AND</u>		
	D.2	Initiate action to establish secondary containment boundary.	Immediately
	<u>AND</u>		
	D.3	Initiate action to isolate each secondary containment penetration flow path or verify it can be automatically or manually isolated from the control room.	Immediately
	<u>AND</u>		
	D.4	Initiate action to verify one SGT subsystem is capable of being placed in operation.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time of Condition C or D not met. <u>OR</u> DRAIN TIME < 1 hour.	E.1 Initiate action to restore DRAIN TIME to ≥ 36 hours.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify DRAIN TIME ≥ 36 hours.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.2	Verify, for a required low pressure ECCS injection/spray subsystem, the suppression pool water level is ≥ 12 ft 8 inches.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.3	Verify, for a required High Pressure Core Spray (HPCS) System, the: a. Suppression pool water level is ≥ 12 ft 8 inches; or b. RCIC storage tank available water volume is ≥ 125,000 gal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.4	Verify, for the required ECCS injection/spray subsystem, locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.5	-------------------NOTES------------------ 1. Operation may be through the test return line. 2. Credit may be taken for normal system operation to satisfy this SR. --- Operate the required ECCS injection/spray subsystem for ≥ 10 minutes.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.6	Verify each valve credited for automatically isolating a penetration flow path actuates to the isolation position on an actual or simulated isolation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.7	-------------------NOTE-------------------- Vessel injection/spray may be excluded. --- Verify the required ECCS injection/spray subsystem can be manually operated.	In accordance with the Surveillance Frequency Control Program

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.3 RCIC System

LCO 3.5.3 The RCIC System shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 with reactor steam dome pressure > 150 psig.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC System inoperable.	A.1 Verify by administrative means High Pressure Core Spray System is OPERABLE. <u>AND</u> A.2 Restore RCIC System to OPERABLE status.	1 hour 123 14 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 Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	Verify the RCIC System locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program
SR 3.5.3.2	-------------------NOTE-------------------- Not required to be met for system vent flow paths opened under administrative control. ---	
	Verify each RCIC System 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 3.5.3.3	-------------------NOTE-------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---	
	Verify, with RCIC steam supply pressure ≤ 1045 psig and ≥ 920 psig, the RCIC pump can develop a flow rate ≥ 600 gpm against a system head corresponding to reactor pressure.	In accordance with the Surveillance Frequency Control Program
SR 3.5.3.4	-------------------NOTE-------------------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---	
	Verify, with RCIC steam supply pressure ≤ 150 psig and ≥ 135 psig, the RCIC pump can develop a flow rate ≥ 600 gpm against a system head corresponding to reactor pressure.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.3.5	-------------------NOTE------------------- Vessel injection may be excluded. -- Verify the RCIC System actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more required primary containment air locks inoperable for reasons other than Condition A or B.	C.1 Initiate action to evaluate primary containment overall leakage rate per LCO 3.6.1.1, using current air lock test results.	Immediately
	AND	
	C.2 Verify a door is closed in the affected air lock.	1 hour
	AND	
	C.3 Restore air lock to OPERABLE status.	24 hours OR -----NOTE------ Not applicable if leakage exceeds limits or if loss of function. --------------- In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time of Condition A, B, or C not met in MODE 1, 2, or 3.	D.1 Be in MODE 3.	12 hours
	AND	
	D.2 Be in MODE 4.	36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more penetration flow paths with one PCIV inoperable, except due to 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. <u>AND</u>	4 hours or in accordance with the Risk Informed Completion Time Program except for main steam line and excess flow check valves (EFCVs) <u>AND</u> 8 hours or in accordance with the Risk Informed Completion Time Program for main steam line <u>AND</u> 12 hours or in accordance with the Risk Informed Completion Time Program for EFCVs (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 --------NOTE--------- Isolation devices in high radiation areas may be verified by use of administrative means. ---------------------- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation for isolation devices outside primary containment, drywell, and steam tunnel <u>AND</u> Prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment, drywell, or steam tunnel

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One or more penetration flow paths with one or more primary containment purge valves not within purge valve 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.	24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>AND</u>		
	D.2	---------NOTE-------- Isolation devices in high radiation areas may be verified by use of administrative means. --------------------- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation for isolation devices outside primary containment <u>AND</u> Prior to entering MODE 2 or 3 from MODE 4 if not performed within the previous 92 days for isolation devices inside primary containment
	<u>AND</u>		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	D.3 Perform SR 3.6.1.3.5 for the resilient seal purge valves closed to comply with Required Action D.1.	Once per 92 days following isolation
E. Required Action and associated Completion Time of Condition A, B, C, or D not met in MODE 1, 2, or 3.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours
F. Required Action and associated Completion Time of Condition A, B, C, or D not met for PCIV(s) required to be OPERABLE during movement of recently irradiated fuel assemblies in the primary or secondary containment.	F.1 --------NOTE--------- LCO 3.0.3 is not applicable. --------------------- Suspend movement of recently irradiated fuel assemblies in primary and secondary containment.	Immediately

3.6 CONTAINMENT SYSTEMS

3.6.1.6 Low-Low Set (LLS) Valves

LCO 3.6.1.6 The LLS function of five safety/relief valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One LLS valve inoperable.	A.1 Restore LLS valve to OPERABLE status.	14 days OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	------------NOTE------------ LCO 3.0.4.a is not applicable when entering MODE 3. ---------------------------- B.1 Be in MODE 3.	 12 hours
C. Two or more LLS valves inoperable.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.7 Residual Heat Removal (RHR) Containment Spray System

LCO 3.6.1.7 Two RHR containment spray subsystems shall be OPERABLE.

---------------------------NOTE---------------------------
One RHR containment spray subsystem may be inoperable during alignment and operation for decay heat removal with reactor steam dome pressure less than the residual heat removal cut in permissive pressure.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR containment spray subsystem inoperable.	A.1 Restore RHR containment spray subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Two RHR containment spray subsystems inoperable.	B.1 Restore one RHR containment spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	------------NOTE------------ LCO 3.0.4.a is not applicable when entering MODE 3. ---------------------------- C.1 Be in MODE 3.	12 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

LCO 3.6.2.3 Two RHR suppression pool cooling subsystems shall be OPERABLE.

---------------------------NOTE---------------------------
One RHR suppression pool cooling subsystem may be inoperable during alignment and operation for decay heat removal with reactor steam dome pressure less than the residual heat removal cut in permissive pressure.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool cooling subsystem inoperable.	A.1 Restore RHR suppression pool cooling 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 of Condition A not met.	------------NOTE------------ LCO 3.0.4.a is not applicable when entering MODE 3. ---------------------------- B.1 Be in MODE 3.	 12 hours
C. Two RHR suppression pool cooling subsystems inoperable.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.4 Suppression Pool Makeup (SPMU) System

LCO 3.6.2.4 Two SPMU subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Combined upper containment pool and suppression pool water levels not within limit.	A.1 Restore upper containment pool and suppression pool water levels to within limit.	4 hours
B. Upper containment pool water temperature not within limit.	B.1 Restore upper containment pool water temperature to within limit.	24 hours
C. One SPMU subsystem inoperable for reasons other than Condition A or B.	C.1 Restore SPMU subsystem to OPERABLE status.	7 days <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 4.	12 hours 36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Drywell air lock inoperable for reasons other than Condition A or B.	C.1	Verify a door is closed.	1 hour
	AND		
	C.2	Restore air lock to OPERABLE status.	24 hours OR -----NOTE------ Not applicable if leakage exceeds limits or if loss of function. --------------- In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	12 hours
	AND		
	D.2	Be in MODE 4.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more penetration flow paths with one required drywell isolation valve inoperable.	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.	8 hours OR In accordance with the Risk Informed Completion Time Program
	AND		
	A.2	--------NOTE--------- Isolation devices in high radiation areas may be verified by use of administrative means. --------------------- Verify the affected penetration flow path is isolated.	Prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days

(continued)

3.7 PLANT SYSTEMS

3.7.1 Division 1 and 2 Shutdown Service Water (SX) Subsystems and Ultimate Heat Sink (UHS)

LCO 3.7.1 Division 1 and 2 SX subsystems and the UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. UHS water volume not within limit	A.1 Restore UHS water volume to within limit.	90 days
------------NOTE------------ Not applicable during replacement of Division 2 SX pump during the Division 2 SX system outage window from October 26 through November 8, 2015. --------------------------- B. Division 1 or 2 SX subsystem inoperable.	------------NOTES------------ 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating," for diesel generator made inoperable by SX. 2. Enter applicable Conditions and Required Actions of LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," for RHR shutdown cooling subsystem made inoperable by SX. ------------------------------ B.1 Restore SX subsystem to OPERABLE status.	 72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

3.7 PLANT SYSTEMS

3.7.6 Main Turbine Bypass System

LCO 3.7.6 The Main Turbine Bypass System shall be OPERABLE.

OR

The following limits are made applicable:

a. Reactor THERMAL POWER limit for an inoperable Main Turbine Bypass System as specified in the COLR; and

b. LCS 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limit for an inoperable Main Turbine Bypass System as specified in the COLR; and

c. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limit for an inoperable Main Turbine Bypass System as specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 21.6% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	2 hours OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 21.6% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify one complete cycle of each main turbine bypass valve.	In accordance with the Surveillance Frequency Control Program
SR 3.7.6.2	Perform a system functional test.	In accordance with the Surveillance Frequency Control Program
SR 3.7.6.3	Verify the TURBINE BYPASS SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources—Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electric Power Distribution System; and

b. Three diesel generators (DGs).

APPLICABILITY: MODES 1, 2, and 3.

-----NOTE-----
Division 3 AC electrical power sources are not required to be OPERABLE when High Pressure Core Spray System is inoperable.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore offsite circuit to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND		

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.4	Restore required DG to OPERABLE status.	72 hours or in accordance with the Risk Informed Completion Time Program from discovery of an inoperable Division 3 DG <u>AND</u> 14 days or in accordance with the Risk Informed Completion Time Program
C. Two offsite circuits inoperable.	C.1	Declare required feature(s) inoperable when the redundant required feature(s) are inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	C.2	Restore one offsite circuit to OPERABLE status.	24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One offsite circuit inoperable. AND One required DG inoperable.	D.1 Restore offsite circuit to OPERABLE status.	12 hours OR In accordance with the Risk Informed Completion Time Program
	OR	
	D.2 Restore required DG to OPERABLE status.	12 hours OR In accordance with the Risk Informed Completion Time Program
E. Two required DGs inoperable.	E.1 Restore one required DG to OPERABLE status.	2 hours OR 24 hours if Division 3 DG is inoperable
F. Required Action and Associated Completion Time of Condition A, B, C, D, or E not met.	-------------NOTE------------ LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------- F.1 Be in MODE 3.	12 hours
G. Three or more required AC sources inoperable.	G.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each 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 ≥ 4084 V and ≤ 4300 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
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 operates for ≥ 60 minutes at a load ≥ 3482 kW for DG 1A, ≥ 3488 kW for DG 1B, and ≥ 1980 kW for DG 1C.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.4	Verify each day tank contains ≥ 385 gal of fuel oil for DG 1A and DG 1B and ≥ 240 gal for DG 1C.	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 the storage tank to the day tank.	In accordance with the Surveillance Frequency Control Program
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 ≤ 12 seconds, voltage ≥ 4084 V and frequency ≥ 58.8 Hz; and b. Steady state voltage ≥ 4084 V and ≤ 4300 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.8	------------------NOTE------------------ This Surveillance shall not be performed in MODE 1 or 2 (not applicable to Division 3 AC sources). However, credit may be taken for unplanned events that satisfy this SR. -- Verify automatic and manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.9	------------------NOTE------------------ 1. Credit may be taken for unplanned events that satisfy this SR. 2. If performed with DG synchronized with offsite power, it shall be performed at a power factor ≤ 0.9. -- Verify each DG rejects a load greater than or equal to its associated single largest post accident load and following load rejection, the engine speed is maintained less than nominal plus 75% of the difference between nominal speed and the overspeed trip setpoint or 15% above nominal, whichever is lower.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.10	------------------NOTE------------------ Credit may be taken for unplanned events that satisfy this SR. -- Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤ 5000 V for DG 1A and DG 1B and ≤ 5824 V for DG 1C during and following a load rejection of a load ≥ 3482 kW for DG 1A, ≥ 3488 kW for DG 1B, and ≥ 1980 kW for DG 1C.	In accordance with the Surveillance Frequency Control Program

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources——Operating

LCO 3.8.4 The Division 1, Division 2, Division 3, and Division 4 DC electrical power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One battery charger on Division 1 or 2 inoperable.	A.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage.	2 hours
	AND	
	A.2 Verify battery float current $\leq$ 2 amps.	Once per 12 hours
	AND	
	A.3 Restore battery charger to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. One battery on Division 1 or 2 inoperable.	B.1 Restore battery to OPERABLE status.	2 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Division 1 or 2 DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore Division 1 and 2 DC electrical power subsystems to OPERABLE status.	2 hours OR In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time for Condition A, B, or C not met.	-------------NOTE------------ LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------- D.1 Be in MODE 3.	 12 hours
E. Division 3 or 4 DC electrical power subsystem inoperable.	E.1 Declare High Pressure Core Spray System inoperable.	Immediately
F. Required Action and associated Completion Time for Condition E not met.	F.1 Be in MODE 3. AND F.2 Be in MODE 4.	12 hours 36 hours

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters—Operating

LCO 3.8.7 The Division 1, 2, 3, and 4 inverters, and A and B RPS solenoid bus inverters shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

-----------------------------------NOTE-----------------------------------
Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," with any uninterruptible AC bus de-energized.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Division 1 or 2 inverter inoperable.	A.1 Restore Division 1 and 2 inverters to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	-------------NOTE------------ LCO 3.0.4.a is not Applicable when entering MODE 3. ----------------------------- B.1 Be in MODE 3.	 12 hours
C. One or more Division 3 or 4 inverters inoperable.	C.1 Declare High Pressure Core Spray System inoperable.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One RPS solenoid bus inverter inoperable.	D.1.1 Transfer RPS bus to alternate power source. AND D.1.2 Verify RPS bus supply frequency ≥ 57 Hz. OR D.2 De-energize RPS bus.	1 hour Once per 8 hours thereafter 1 hour
E. Both RPS solenoid bus inverters inoperable.	E.1 De-energize one RPS solenoid bus.	1 hour
F. Required Action and associated Completion Time for Condition C, D, or E not met.	F.1 Be in MODE 3. AND F.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

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

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems——Operating

LCO 3.8.9 Division 1, 2, and 3 AC, Division 1, 2, 3, and 4 DC, and Division 1, 2, 3, and 4 uninterruptible AC bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

----------------------------NOTE----------------------------
Division 3 and 4 electrical power distribution subsystems are not required to be OPERABLE when High Pressure Core Spray System is inoperable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Division 1 or 2 AC electrical power distribution subsystems inoperable.	A.1 Restore Division 1 and 2 AC electrical power distribution subsystems to OPERABLE status.	8 hours OR -----NOTE------ Not applicable if loss of function. --------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more Division 1 or 2 uninterruptible AC bus distribution subsystems inoperable.	B.1 Restore Division 1 and 2 uninterruptible AC bus distribution subsystems to OPERABLE status.	8 hours OR -----NOTE------ Not applicable if loss of function. --------------- In accordance with the Risk Informed Completion Time Program
C. One or more Division 1 or 2 DC electrical power distribution subsystems inoperable.	C.1 Restore Division 1 and 2 DC electrical power distribution subsystems to OPERABLE status.	2 hours OR -----NOTE------ Not applicable if loss of function. --------------- In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time of Condition A, B, or C not met.	-------------NOTE------------ LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------- D.1 Be in MODE 3.	 12 hours
E. One or more Division 3 or 4 AC, DC, or uninterruptible AC bus electrical power distribution subsystems inoperable.	E.1 Declare High Pressure Core Spray System inoperable.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Two or more divisions with inoperable distribution subsystems that result in a loss of function.	F.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 uninterruptible AC bus electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program

5.5 Programs and Manuals (continued)

5.5.15 Control Room Envelope Habitability Program (continued)

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one subsystem of the Control Room Ventilation System, operating at the flow rate required by the VFTP, at a Frequency of 24 months on a STAGGERED TEST BASIS. The results shall be trended and used as a part of the 24 month assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraph c and d, respectively.

5.5.16 Surveillance Frequency Control Program

This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI 04-10, “Risk-Informed Method for control of Surveillance Frequencies,” Revision 1.

c. The provisions of Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

(continued)

5.5 Programs and Manuals (continued)

5.5.17 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 used to support this license amendment, 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.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Deleted

5.6.2 Annual Radiological Environmental Operating Report

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 1 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.3 Radioactive Effluent Release Report

The Radioactive Effluent Release Report covering the operation of the unit during the previous calendar year shall be submitted by May 1 of each year. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and process control program and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.6.4 Deleted

(continued)

5.6 Reporting Requirements (continued)

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. LCO 3.2.1, Average Planar Linear Heat Generation Rate (APLHGR),

2. LCO 3.2.2, Minimum Critical Power Ratio (MCPR) and $MCPR_{99.9\%}$,

3. LCO 3.2.3, Linear Heat Generation Rate (LHGR),

4. LCO 3.3.1.1, RPS Instrumentation (SR 3.3.1.1.14),

5. LCO 3.3.1.3, Oscillation Power Range Monitor (OPRM) Instrumentation, and

6. LCO 3.7.6, Main Turbine Bypass System, (cycle dependent thermal power limits for an inoperable Main Turbine Bypass System).

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC in

(1) General Electric Standard Application for Reactor Fuel (GESTAR), NEDE-24011-P-A, or

(2) NEDO-32465, "BWR Owners' Group Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology and Reload Applications."

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 238 TO

FACILITY OPERATING LICENSE NO. NPF-62

EXELON GENERATION COMPANY, LLC

CLINTON POWER STATION, UNIT NO. 1

DOCKET NO. 50-461

1.0 INTRODUCTION

By application dated April 30, 2020 (Reference 1), as supplemented by letters dated November 24, 2020 (Reference 2), and March 23, 2021 (Reference 3), Exelon Generation Company, LLC (Exelon, the licensee) submitted a license amendment request (LAR) for Clinton Power Station, Unit 1 (CPS).

The amendment 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 Initiative 4b," dated July 2, 2018 (Reference 4). The U.S. Nuclear Regulatory Commission (NRC or Commission) issued a final model safety evaluation (SE) approving TSTF-505, Revision 2, on November 21, 2018 (Reference 5).

The supplemental letters dated November 24, 2020, and March 23, 2021, 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* (FR) on June 16, 2020 (85 FR 36435).

2.0 REGULATORY EVALUATION

2.1 Description of Risk-Informed Completion Time Program

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 Times (CTs). 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., shut down the reactor).

Topical Report (TR) Nuclear Energy Institute (NEI) 06-09-A, "Risk-Informed Technical Specifications Initiative 4b: Risk-Managed Technical Specifications (RMTS)," October 2012, Revision 0 (Reference 6) 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.

2.2 Description of TS Changes

The licensee's letter dated April 30, 2020, submittal, requested approval to add a RICT program to the Administrative Controls section of the TS, and modify selected CTs to permit extending the CTs, provided risk is assessed and managed as described in NEI 06-09-A. The licensee's application for the changes proposed to use NEI 06-09-A and included documentation regarding the technical adequacy 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," March 2009 (Reference 7).

2.2.1 TS 1.0 Use and Application

Example 1.3-8, would be added to TS 1.3, CTs, 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 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.

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, Condition A is exited and, therefore, the required actions of Condition B may be terminated.

2.2.2 TS 5.5.17 RICT program

TS 5.5.17, which describes the RICT program, would be added to the TS and reads as follows:

<u>Risk-Informed Completion Time Program</u>

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 used to support this license amendment, 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.

2.2.3 Application of the RICT Program to Existing LCOs and Conditions

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.”

Individual LCO Required Actions and CTs modified by the proposed change are identified below. The changed portion is indicated in italics.

LCO 3.1.7 Two SLC [standby liquid control] subsystems shall be OPERABLE.

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

LCO 3.3.1.1 The RPS [reactor protection system] instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel inoperable.	A.1 Place one channel in affected Function in trip.	48 hours <u>OR</u> *In accordance with the Risk Informed Completion Time Program*
B. One or more Functions with two channels inoperable.	B.1 Place one channel in affected Function in trip.	6 hours <u>OR</u> *In accordance with the Risk Informed Completion Time Program*

LCO 3.3.4.1 Four channels for each EOC-RPT [end of cycle - recirculation pump trip] instrumentation Function listed below shall be OPERABLE:

a. Turbine Stop Valve (TSV) Closure; and

b. Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure–Low.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel inoperable.	A.1 Restore channel to OPERABLE status. <u>OR</u> A.2 --------NOTE--------- Not applicable if inoperable channel is the result of an inoperable breaker. ------------------------ Place one channel in affected Function in trip.	48 hours <u>OR</u> *In accordance with the Risk Informed Completion Time Program* 48 hours <u>OR</u> *In accordance with the Risk Informed Completion Time Program*

B. One or more Functions with two channels inoperable.	B.1 Place one channel in affected Function in trip.	6 hours _OR_ *In accordance with the Risk Informed Completion Time Program*

LCO 3.3.6.1 The primary containment and drywell isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
-----------NOTE--------------- Only applicable to Main Steam Line (MSL) isolation Functions. ----------------------------------- A. One or more Functions with one channel inoperable.	A.1 Place one channel in affected function in trip.	48 hours _OR_ *In accordance with the Risk Informed Completion Time Program*
-----------NOTE--------------- Only applicable to MSL isolation Functions. ----------------------------------- B. One or more Functions with two channels inoperable.	B.1 Place one channel in affected function in trip.	6 hours _OR_ *In accordance with the Risk Informed Completion Time Program*

LCO 3.3.6.5 Two relief and LLS [low-low set] instrumentation trip systems shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One trip system inoperable.	A.1 Restore trip system to OPERABLE status.	7 days _OR_ *In accordance with the Risk Informed Completion Time Program*

LCO 3.5.1 Each ECCS [emergency core cooling system] injection/spray subsystem and the Automatic Depressurization System (ADS) function of seven safety/relief valves shall be OPERABLE.

---------------------------NOTE---
One low pressure coolant injection (LPCI) subsystem may be inoperable during alignment and operation for decay heat removal with reactor steam dome pressure less than the residual heat removal cut in permissive pressure.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	7 days <u>*OR*</u> *In accordance with the Risk Informed Completion Time Program*
B. HPCS [high pressure core spray] System inoperable.	B.2 Restore HPCS System to OPERABLE status.	14 days <u>*OR*</u> *In accordance with the Risk Informed Completion Time Program*
C. Two ECCS injection subsystems inoperable. <u>OR</u> One ECCS injection and one ECCS spray subsystem inoperable.	C.1 Restore one ECCS injection/spray subsystem to OPERABLE status.	72 hours <u>*OR*</u> *In accordance with the Risk Informed Completion Time Program*
E. One ADS valve inoperable.	E.1 Restore ADS valve to OPERABLE status.	14 days <u>*OR*</u> *In accordance with the Risk Informed Completion Time Program*

F. One ADS valve inoperable. AND One low pressure ECCS injection/spray subsystem inoperable.	F.1 Restore ADS valve to OPERABLE status. OR F.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours *OR* *In accordance with the Risk Informed Completion Time Program* 72 hours *OR* *In accordance with the Risk Informed Completion Time Program*

LCO 3.5.3 The RCIC [reactor core isolation cooling] System shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC System inoperable.	A.2 Restore RCIC System to OPERABLE status.	14 days *OR* *In accordance with the Risk Informed Completion Time Program*

LCO 3.6.1.3 Each PCIV [primary containment isolation valve] shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more penetration flow paths with one PCIV inoperable, except due to 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* except for main steam line and excess flow check valves (EFCVs) AND 8 hours *or in accordance with the Risk Informed Completion Time Program* for main steam line

	        AND	AND 12 hours *or in accordance with the Risk Informed Completion Time Program* for EFCVs (continued)
A. (continued)	A.2 --------NOTE--------- Isolation devices in high radiation areas may be verified by use of administrative means. -------------------------- Verify the affected penetration flow path is isolated.	 Once per 31 days *following isolation* for isolation devices outside primary containment, drywell, and steam tunnel AND Prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment, drywell, or steam tunnel
D. One or more penetration flow paths with one or more primary containment purge valves not within purge valve 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 D.2 --------NOTE--------- Isolation devices in high radiation areas may be	24 hours *OR* *In accordance with the Risk Informed Completion Time Program*

	verified by use of administrative means. -------------------------- Verify the affected penetration flow path is isolated.	 Once per 31 days *following isolation* for isolation devices outside primary containment AND Prior to entering MODE 2 or 3 from MODE 4 if not performed within the previous 92 days for isolation devices inside primary containment
	AND D.3 Perform SR [surveillance requirement] 3.6.1.3.5 for the resilient seal purge valves closed to comply with Required Action D.1.	 Once per 92 days *following isolation*

LCO 3.6.1.7 Two RHR [residual heat removal] containment spray subsystems shall be OPERABLE.

----------------------------NOTE--
One RHR containment spray subsystem may be inoperable during alignment and operation for decay heat removal with reactor steam dome pressure less than the residual heat removal cut in permissive pressure.

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

LCO 3.6.2.3 Two RHR suppression pool cooling subsystems shall be OPERABLE.

----------------------------NOTE---
One RHR suppression pool cooling subsystem may be inoperable during alignment and operation for decay heat removal with reactor steam dome pressure less than the residual heat removal cut in permissive pressure.

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

LCO 3.6.2.4 Two SPMU [suppression pool makeup] subsystems shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One SPMU subsystem inoperable for reasons other than Condition A or B.	C.1 Restore SPMU subsystem to OPERABLE status.	7 days OR *In accordance with the Risk Informed Completion Time Program*

LCO 3.6.5.3 One drywell isolation valve in each drywell penetration flow path shall be OPERABLE, except for the drywell vent and purge penetrations in which two drywell isolation valves shall be OPERABLE.

-------------------------NOTE---
This LCO does not apply to OPERABILITY of drywell post-LOCA [loss-of-coolant accident] vacuum relief system valves.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more penetration flow paths with one required drywell isolation valve inoperable.	A.1 Isolate the affected penetration flow path by use of at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	8 hours OR *In accordance with the Risk Informed Completion Time Program*

LCO 3.7.1 Division 1 and 2 SX [shutdown service water] Subsystems and UHS [ultimate heat sink] shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
-----------NOTE----------- Not applicable during replacement of Division 2 SX pump during the Division 2 SX system outage window from October 26 through November 8, 2015. -------------------------- B. Division 1 or 2 SX subsystem inoperable.	------------NOTES--------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC [alternating current] Sources - Operating," for diesel generator made inoperable by SX. 2. Enter applicable Conditions and Required Actions of LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," for RHR shutdown cooling subsystem made inoperable by SX. ----------------------------- B.1 Restore SX subsystem to OPERABLE status.	 72 hours <u>*OR*</u> *In accordance with the Risk Informed Completion Time Program*

LCO 3.7.6 The Main Turbine Bypass System shall be OPERABLE.

<u>OR</u>

The following limits are made applicable:

a. Reactor THERMAL POWER limit for an inoperable Main Turbine Bypass System as specified in the COLR [core operating limits report]; and

b. LCS 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limit for an inoperable Main Turbine Bypass System as specified in the COLR; and

c. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limit for an inoperable Main Turbine Bypass System as specified in the COLR.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	2 hours <u>*OR*</u> *In accordance with the Risk Informed Completion Time Program*

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electric Power Distribution System; and

b. Three diesel generators (DGs).

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One offsite circuit inoperable.	A.2 Restore offsite circuit to OPERABLE status.	72 hours <u>*OR*</u> *In accordance with the Risk Informed Completion Time Program*
B. One required DG inoperable.	B.4 Restore required DG to OPERABLE status.	72 hours *or in accordance with the Risk Informed Completion Time Program* from discovery of an inoperable Division 3 DG <u>AND</u> 14 days *or in accordance with the Risk Informed Completion Time Program*

C. Two offsite circuits inoperable.	C.2 Restore one offsite circuit to OPERABLE status.	24 hours *OR* *In accordance with the Risk Informed Completion Time Program*
D. One offsite circuit inoperable. AND One required DG inoperable.	D.1 Restore offsite circuit to OPERABLE status. OR D.2 Restore required DG to OPERABLE status.	12 hours *OR* *In accordance with the Risk Informed Completion Time Program* 12 hours *OR* *In accordance with the Risk Informed Completion Time Program*

LCO 3.8.4 The Division 1, Division 2, Division 3, and Division 4 DC [direct current] electrical power subsystems shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One battery charger on Division 1 or 2 inoperable.	A.3 Restore battery charger to OPERABLE status.	7 days *OR* *In accordance with the Risk Informed Completion Time Program*
B. One battery on Division 1 or 2 inoperable.	B.1 Restore battery to OPERABLE status.	2 hours OR In accordance with the Risk Informed Completion Time Program

C. Division 1 or 2 DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore Division 1 and 2 DC electrical power subsystem to OPERABLE status.	2 hours <u>OR</u> *In accordance with the Risk Informed Completion Time Program*

LCO 3.8.7 The Division 1, 2, 3, and 4 inverters, and A and B RPS solenoid bus inverters shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Division 1 or 2 inverter inoperable.	A.1 Restore Division 1 and 2 inverters to OPERABLE status.	7 days <u>OR</u> *In accordance with the Risk Informed Completion Time Program*

2.2.4 Variations from TSTF-505, Revision 2

2.2.4.1 Application of the RICT Program to Modified Conditions, Required Actions, and Completion Times

These are Conditions included in TSTF-505, Revision 2, which are applicable when one or more subsystems/channels are inoperable and there is no TS loss of function. The CT of these specific ACTIONS are modified to accommodate a RICT. Example:

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more [channel/subsystem/train] inoperable.	A.1 Restore [channel/subsystem/train] to OPERABLE status.	[24 hours]

The revised ACTIONS requirement states:

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more [channel/subsystem/ train] inoperable.	A.1 Restore [channel/ subsystem/train] to OPERABLE status.	[24 hours] OR ------------NOTE------------ Not applicable when [all/two/four/both] required [channel/subsystem/train] are inoperable. --------------------------------- In accordance with the Risk Informed Completion Time Program

The following Conditions are modified to permit the application of a RICT. The changed portion is indicated in italics.

LCO 3.3.5.1 The ECCS instrumentation for each Function in Table 3.3.5.1-1 shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	B.3 Place channel in trip.	24 hours *OR* *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*
C. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	C.2 Restore channel to OPERABLE status.	24 hours *OR* *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with*

		the Risk Informed Completion Time Program
D. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	D.2.1 Place channel in trip.	24 hour *OR* *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*
E. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	E.2 Restore channel to OPERABLE status.	7 days *OR* *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*

F. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	F.2 Place channel in trip.	96 hours *or in accordance with the Risk Informed Completion Time Program* from discovery of inoperable channel concurrent with HPCS or reactor core isolation cooling (RCIC) inoperable <u>AND</u> *--------------NOTE-----------* *The Risk Informed Completion Time Program is not applicable when trip capability is not maintained.* *---------------------------------* 8 days *or in accordance with the Risk Informed Completion Time Program*
G. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	G.2 Restore channel to OPERABLE status.	96 hours *or in accordance with the Risk Informed Completion Time Program* from discovery of inoperable channel concurrent with HPCS or reactor core isolation cooling (RCIC) Inoperable <u>AND</u> *--------------NOTE-----------* *The Risk Informed Completion Time Program is not applicable when trip capability is not maintained.* *---------------------------------* 8 days *or in accordance with the Risk Informed Completion Time Program*

LCO 3.3.5.3 The RCIC System instrumentation for each Function in Table 3.3.5.3-1 shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	B.2 Place channel in trip.	24 hours OR *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*
D. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	D.2.1 Place channel in trip.	24 hours OR *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*

LCO 3.3.6.1 The primary containment and drywell isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
-----------NOTE---------------- Not applicable to MSL isolation Functions. ----------------------------------- D. One or more required channels inoperable.	D.1 Place channel in trip.	24 hours OR *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*

LCO 3.3.6.3 The RHR Containment Spray System instrumentation for each Function in Table 3.3.6.3-1 shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. As required by Required Action A.1 and referenced in Table 3.3.6.3-1.	B.2 Place channel in trip.	24 hours <u>*OR*</u> *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*
C. As required by Required Action A.1 and referenced in Table 3.3.6.3-1.	C.2 Restore channel to OPERABLE status.	24 hours <u>*OR*</u> *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*

LCO 3.3.8.1 The LOP [loss of power] instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Place channel in trip. AND A.2 ---------NOTE-------------- Only applicable for Functions 1.c, 1.d, 1.e, 2.c, 2.d, and 2.e -------------------------------- Restore channel to OPERABLE status.	1 hour OR --------*NOTE*----------------- *Not applicable when trip capability is not maintained.* --------------------------------- *In accordance with the Risk Informed Completion Time Program* 7 days OR --------*NOTE*----------------- *Not applicable when trip capability is not maintained.* --------------------------------- *In accordance with the Risk Informed Completion Time Program*

LCO 3.6.1.2 Each primary containment air lock shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more required primary containment air locks inoperable for reasons other than Condition A or B.	C.3 Restore air lock to OPERABLE status.	24 hours OR --------*NOTE*----------------- *Not applicable if leakage exceeds limits or if loss of function.* -------------------------------- *In accordance with the Risk Informed Completion Time Program*

LCO 3.6.5.2 The drywell air lock shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Drywell air lock inoperable for reasons other than Condition A or B.	C.2 Restore air lock to OPERABLE status.	24 hours <u>*OR*</u> *--------NOTE-----------------* *Not applicable if leakage exceeds limits or if loss of function.* *--------------------------------* *In accordance with the Risk Informed Completion Time Program*

2.2.4.2 Application of the RICT to Additional ACTIONS Requirements

The following CPS TS Conditions proposed for the RICT program are not listed in TSTF 505, Revision 2.

LCO 3.3.6.4 The SPMU system instrumentation for each Function in Table 3.3.6.4-1 shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. As required by Required Action A.1 and referenced in Table 3.3.6.4-1.	B.2 Place channel in trip.	24 hours <u>*OR*</u> *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*

C. As required by Required Action A.1 and referenced in Table 3.3.6.4-1.	C.2 Restore channel to OPERABLE status.	24 hours _OR_ *--------NOTE-----------------* *Not applicable when trip capability is not maintained.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*

LCO 3.6.1.6 The LLS function of five safety/relief valves shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One LLS valve inoperable.	A.1 Restore LLS valve to OPERABLE status.	14 days _OR_ *In accordance with the Risk Informed Completion Time Program*

LCO 3.8.9 Division 1, 2, and 3 AC, Division 1, 2, 3, and 4, DC, and Division 1, 2, 3, and 4, uninterruptible AC bus electrical power distribution subsystems shall be OPERABLE.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Division 1 or 2 AC electrical power distribution subsystems inoperable.	A.1 Restore Division 1 and 2 AC electrical power distribution subsystems to OPERABLE status.	8 hours _OR_ *--------NOTE-----------------* *Not applicable if loss of function.* *---------------------------------* *In accordance with the Risk Informed Completion Time Program*

B. One or more Division 1 or 2 uninterruptible AC bus distribution subsystems inoperable.	B.1 Restore Division 1 and 2 uninterruptible AC bus distribution subsystems to OPERABLE status.	8 hours <u>*OR*</u> --------*NOTE*----------------- *Not applicable if loss of function.* --------------------------------- *In accordance with the Risk Informed Completion Time Program*
C. One or more Division 1 or 2 DC electrical power distribution subsystems inoperable.	C.1 Restore Division 1 and 2 DC electrical power distribution subsystems to OPERABLE status.	2 hours <u>*OR*</u> --------*NOTE*----------------- *Not applicable if loss of function.* --------------------------------- *In accordance with the Risk Informed Completion Time Program*

2.3 <u>Regulatory Review</u>

2.3.1 Applicable Regulations

Under Section 50.90, "Application for amendment of license, construction permit, or early site permit," of Title 10 of the *Code of Federal Regulations* (10 CFR), whenever a holder of a license wishes to amend the license, including TSs in the license, an application for amendment must be filed, fully describing the changes desired.

The regulation at 10 CFR 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 at 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 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 technical specifications, 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 10 CFR Part 20 of this chapter, and that the health and safety of the public will not be endangered."

The regulation at 10 CFR 50.36(c)(5) states 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 at 10 CFR 50.55a(h), "Protection and safety systems," requires that for nuclear power plants with construction permits issued after January 1, 1971, but before May 13, 1999, protection systems must meet the requirements in IEEE Std 279-1968, "Proposed IEEE Criteria for Nuclear Power Plant Protection Systems," or the requirements in IEEE Std 279-1971[1], "Criteria for Protection Systems for Nuclear Power Generating Stations," or the requirements in IEEE Std 603-1991[1], "Criteria for Safety Systems for Nuclear Power Generating Stations," and the correction sheet dated January 30, 1995. The CPS construction permit was issued on February 24, 1976. The CPS USAR, Chapters 6 and 7 (Reference 12), describes conformance to IEEE Std 279 by system.

2.3.2 Regulatory Guidance

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

- RG 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities."

- RG 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," January 2018 (Reference 8).

- RG 1.177, Revision 1, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," May 2011 (Reference 9).

- NUREG-1855, Revision 1, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decisionmaking," March 2017 (Reference 10).

- NUREG-0800, "Standard Review Plan [SRP] for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition," Chapter 19, Section 19.2, "Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance," June 2007 (Reference 11).

- NEI 06 09 A, "Risk Informed Technical Specifications Initiative 4b: Risk Managed Technical Specifications (RMTS)," October 2012, Revision 0.

[1] Available from Electric Power Research Institute, 3420 Hillview Avenue, Palo Alto, California 94304.

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 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 completion time 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 (LB) changes meet the five key principles stated in Section C of RG 1.174, Revision 3, and the three-tiered approach outlined in Section C of RG 1.177. These key principles and tiers are:

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

Principle 2: The proposed LB change is consistent with the defense in depth (DID) philosophy.

Principle 3: The proposed LB change maintains sufficient safety margins.

Principle 4: When the proposed LB change results in an increase in risk, the increase should be small and consistent with the intent of the Commission's policy statement (60 FR 42622, dated August 16,1995) 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 LB change should be monitored by using performance measures strategies.

Each of these key risk-informed principles and tiers are addressed in NEI 06-09-A. 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. The NRC staff's evaluation of the licensee's proposed use of RICT program against the key safety principles is discussed below.

3.2 Review of Key Principles

Revision 1 of RG 1.177 and RG 1.174, Revision 3, identify five key safety principles to be applied to risk-informed changes to the TSs. Each of these principles are addressed in NEI 06-09-A. The NRC staff's evaluation of the licensee's proposed use of RICTs against these key safety principles is discussed below.

3.2.1 Key Principle 1: Evaluation of Compliance with Current Regulations

Paragraph 50.36(c)(2) of 10 CFR require that LCOs 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 condition can be met.

The CTs in the current TSs were established using experiential data, risk insights, and engineering judgement. The RICT program provides the necessary administrative controls to permit extension of CTs and, thereby, delay reactor shut down or Required Actions, if risk is assessed and managed appropriately within specified limits and programmatic requirements. The addition of the option to determine the CT in accordance with the RICT program would allow an evaluation to determine a configuration-specific CT. The evaluation would be done in accordance with the methodology prescribed in NEI 06-09, and TS 5.5.17. The RICT is limited to a maximum of 30 days (i.e., “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 by the RICT program 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 safety principle of RG 1.174, Revision 3, and RG 1.177, Revision 1.

3.2.2 Key Principle 2: Evaluation of Defense in Depth (DID)

DID is an approach to designing and operating nuclear facilities that prevents and mitigates accidents that release radiation or hazardous materials. The key is creating multiple independent and redundant layers of defense to compensate for potential human and mechanical failures so that no single layer, no matter how robust, is exclusively relied upon. DID includes the use of access controls, physical barriers, redundant and diverse key safety functions, and emergency response measures.

In RG 1.174, Revision 3, the NRC identified the following considerations used for evaluating how the LB 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 proposed change represents a robust technical approach that preserves a reasonable balance among redundant and diverse key safety function that provide avoidance of core damage, avoidance of containment failure, and consequence mitigation. The three-tiered approach to risk-informed TS CT changes provides additional assurance that defense-in-depth will not be significantly impacted by such changes to the licensing basis. The licensee is

proposing no changes to the design of the plant or any operating parameter, no new operating configurations, and no new changes to the design basis in the proposed changes to the TS.

Since no changes to the design of the plant or any operating parameter, no new operating configuration, and no new changes to the design basis are proposed, the NRC staff finds that the 10 CFR 50.55a(h) requirements continue to be met.

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). A configuration-specific RICT may not be used if the system has lost the capability to perform its safety function(s). 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.

Use of Compensatory Measures to Retain DID

In NEI 06-09, addresses potential compensatory actions and RMA measures by stating, in generic terms, that compensatory measures may include but are not limited to the following:

- Reduce the duration of risk-sensitive activities.
- Remove risk-sensitive activities from the planned work scope.
- Reschedule work activities to avoid high risk-sensitive equipment outages or maintenance states that result in high-risk plant configurations.
- Accelerate the restoration of out-of-service equipment.
- Determine and establish the safest plant configuration.

NEI 06-09, requires that compensatory measures be initiated when the PRA calculated RMA time (RMAT) is exceeded, or for preplanned maintenance for which the RMAT is expected to be exceeded, RMAs shall be implemented at the earliest appropriate time. Therefore, quantitative risk analysis, the qualitative considerations, and the prohibition on loss of all trains of a required system assure a reasonable balance of DID is maintained to ensure protection of public health and safety.

3.2.2.1 Evaluation of Electrical Power Systems

According to Revision 21 of the Updated Safety Analysis Report (USAR) (Reference 12), the plant is designed such that the safety functions are maintained assuming a single failure within the electrical power system. By incorporating an electrical power supply perspective, this concept is further reflected in a number of principal design criteria. Single-failure requirements

are typically suspended for the time that a plant is not meeting an LCO (i.e., in an ACTION statement). This section considers the plant configurations from a DID perspective.

The licensee has requested to use the RICT program to extend the existing CT for the following TS 3.8, "Electrical Power Systems," condition(s). The NRC staff's evaluation of the proposed changes considered a number of potential plant conditions allowed by the proposed RICTs. The NRC staff also considered the available redundant or diverse means to respond to various plant conditions. In these evaluations, the NRC staff examined the safety significance of different plant conditions resulting in both shorter and longer CTs. The plant conditions evaluated are discussed in more detail below.

The NRC staff reviewed information pertaining to the proposed electrical power systems TS conditions in the application, the USAR, and applicable TS LCO and TS Bases to verify that the capability of the affected electrical power systems to perform their safety functions (assuming no additional failures) is maintained. To achieve that objective, the staff verified whether each proposed TS condition's design success criteria reflect the redundant or absolute minimum electrical power source/subsystem required to be operable by the LCOs to support the safety functions necessary to mitigate postulated design-basis accidents (DBAs), safely shut down the reactor, and maintain the reactor in a safe shutdown condition. The NRC staff further reviewed the remaining credited power source/equipment to verify whether the proposed condition satisfies its design success criteria. In conjunction with reviewing the remaining credited power source/equipment, the NRC staff considered supplemental electrical power sources/equipment (not necessarily required by the LCOs and either safety or nonsafety-related) that is available at CPS and capable of performing the same safety function that would be performed by the inoperable electrical power source/equipment. In addition, the NRC staff reviewed the proposed RMA examples for reasonable assurance that these RMAs are appropriate to monitor and control risk for applicable TS conditions.

3.2.2.1.1 Loss of Power (LOP) Instrumentation (TS 3.3.8.1)

<u>Description of the LOP Instrumentation</u>

Revision 21 of the CPS USAR, Chapter 8, "Electric Power," and TS Bases Section B.3.3.8.1, "Loss of Power (LOP) Instrumentation," indicate that the LOP instrumentation monitors the 4.16 kV (kilovolt) emergency buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the voltage monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite DG power sources. Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for the Division 1, 2, and 3, buses is monitored at two levels, which can be considered as two different undervoltage functions: loss of voltage and degraded voltage.

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel relating to the loss of voltage and degraded voltage functions. Each Function must have a required number of OPERABLE channels for each 4.16 kV emergency bus with the setpoints within the allowable values specified in the TS. A channel is considered inoperable if its actual trip setpoint is not within its required allowable value.

Description of Loss of Voltage Functions (TS Table 3.3.8.1-1; Functions 1.a, 1.b, 2.a, 2.b)

Loss of voltage on a 4.16 kV emergency bus indicates that offsite power (provided by either of two offsite circuits) may be completely lost to the respective emergency bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to DG power when the associated bus voltage drops below the loss of voltage function allowable value. This ensures that adequate power will be available to the required equipment.

The loss of voltage function is also provided a time delay. The time delay allowable value is long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that power is available to the required equipment.

According to TS Table 3.3.8.1-1, there are six channels of 4.16 kV emergency bus loss of voltage function instrumentation for each Division 1 and 2, and four channels for Division 3, which are required to be OPERABLE. Each channel of Division 1 and Division 2 consists of an inverse time delay relay providing a voltage function and a time delay function. Division 3 has four loss of voltage relays/channels and a single time delay relay.

Description of Degraded Voltage Functions (TS Table 3.3.8.1-1 - Functions 1c, 1.d, 1.e, 2.c, 2.d, and 2.e)

A reduced voltage condition on a 4.16 kV emergency bus indicates that while offsite power may not be completely lost to the respective emergency bus, power may be insufficient for starting large motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from offsite power to onsite DG power when the voltage on the bus drops below the degraded voltage function allowable value. This ensures that adequate power will be available to the required equipment.

The purpose of this instrumentation is to ensure that sufficient power will be available to support the ECCS function during a LOCA. During a LOCA, the ECCS and other safety systems will be initiated at the start of the event. This large loading of the safety buses results in a voltage transient of sufficient magnitude to start the degraded voltage timers. If the degraded voltage relays do not reset, which requires the voltage to be restored to a level above the relay reset setpoint, the bus undervoltage time delay relays will trip, resulting in bus transfer to the DGs.

According to TS Table 3.3.8.1-1, each division has two channels of degraded voltage relays and a single channel of time delay relay, which are required to be OPERABLE.

TS 3.3.8.1 - Changes Relating to LOP Instrumentation

Refer to Section 2.2 of this SE for a detailed view of the TS changes.

Evaluation of TS Changes Relating to LOP Instrumentation

According to TS 3.3.8.1, Action A.1, the current TS requires placement of any channel relating to loss of voltage or degraded voltage functions in the trip position within one hour. The licensee has proposed to extend the completion time as per the RICT program. According to Action A.2, the current TS requires restoration of any channel relating to the degraded voltage function within 7 days. The licensee has proposed to extend the completion time as per the RICT program. However, the extension in completion time will not be applicable if the trip

capability is not maintained. If any of the actions and associated completion times are not met, the associated bus DG is required to be declared inoperable immediately.

In its letter dated November 24, 2020, the licensee explained the loss of functions, as follows if any inoperable channel relating to loss of voltage or degraded voltage function is placed in the trip position:

> The Division 1 and 2 emergency bus Loss of Voltage Function is monitored by two undervoltage relays on the emergency bus and two undervoltage relays on each of the two offsite power sources. This results in a total of six relay/channels for the Loss of Voltage Function for each Division. Each of these relays is an inverse time delay relay. The outputs of these relays are arranged in a two-out-of-two taken three times logic configuration to start the respective Divisional Diesel Generator. Any relay/channel failing will result in the respective Diesel Generator not starting.
>
> The Division 3 emergency bus Loss of Voltage Function is monitored by four undervoltage relays whose outputs are arranged in a one-out-of-two taken twice logic configuration. The output of this logic inputs to a time delay relay. A failure of a channel associated with Function 2.a [Degraded Voltage Function for Division 3] will not result in a loss of the function. However, a failure of Function 2.b [Degraded Time Function for Division 3] will result in the Division 3 Diesel Generator not starting.
>
> Each Division 1, Division 2, and Division 3 emergency bus Degraded Voltage Function is monitored by two undervoltage relays for each emergency bus whose outputs are arranged in a two-out-of-two logic configuration. The output of this logic inputs to a time delay relay on each emergency bus. Any relay/channel failing will result in the respective Diesel Generator not starting.

The NRC staff finds that based on logic explained by the licensee in its above response, in most cases of one or more channel failures, the Loss of Power Instrumentation will continue to serve its design function (i.e., detect loss of voltage or degraded voltage). The TS change also has a Note stating that the RICT is not applicable when the trip capability is not maintained (i.e., unable to meet its design function).

In its letter dated November 24, 2020, the licensee also explained that in the RICT PRA modelling, the "Inoperability of One or more channels" is modeled as a failure of the autostart mode of the associated DG. The manual start mode of the associated DG is still considered available in the RICT model. The NRC staff finds this aspect of the RICT modelling reasonable and, therefore, acceptable.

The above extension in CT will only be applicable when “One or more channels [are] inoperable” and will not result in a loss of the design function (i.e., unable to detect loss of voltage or degraded voltage). For instrumentation that has the potential for a configuration in which trip capability is not maintained, a Note was added to the Completion Time which prohibits applying a RICT when trip capability is not maintained. The associated DG, if declared inoperable, can be started manually, thus, providing a partial safety function for certain design events which do not require immediate/auto starting of DG.

The NRC staff finds that because of redundancies in the availability of the offsite and onsite power sources the LOP design has sufficient redundancy, diversity, and DID to protect against common cause failures and potential single failure when using the RICT Program. Therefore, the staff finds the above TS changes are acceptable.

3.2.2.1.2 AC Sources – Operating (TS 3.8.1)

Description of the AC Sources

CPS USAR Section 8, and TS Bases B.3.8.1, describe the Unit Class 1E AC Electrical Power Distribution System AC Sources as consisting of the offsite power sources and the onsite standby power sources (DGs 1A, 1B, and 1C). As required by 10 CFR Part 50, Appendix A, General Design Criteria 17, the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the engineered safety feature (ESF) systems.

The Class 1E AC distribution system supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 4.16 kV ESF bus. Each ESF bus has two separate and independent offsite sources of power. Each ESF bus has a dedicated onsite DG. The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to the switchyard from the transmission network. From the switchyard, one 345 kV circuit provides AC power to each 4.16 kV ESF bus. An electrically and physically independent 138 kV power source provides a second completely independent circuit to each 4.16 kV ESF bus. The offsite AC electrical power sources are designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. A DG starts automatically on a LOCA signal (i.e., low reactor water level signal or high drywell pressure signal) or on an ESF bus degraded voltage or undervoltage signal. In the event of a loss of offsite power (LOOP), the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shut down and to mitigate the consequences of a design basis accident such as a LOCA.

TS 3.8.1 - Changes Relating to AC Power – Operating

Refer to Section 2.2 of this SE for a detailed view of the TS changes.

Evaluation of TS Changes Relating to AC Sources - Operating

For each change identified below, the NRC staff reviewed the information pertaining to the proposed TS change in the LAR, the USAR, and applicable TS LCO and TS Bases to verify that the capability of the affected electrical power systems to perform their safety functions (assuming no additional failures) is maintained. To achieve that objective, the NRC staff verified that the proposed TS condition's design success criteria (as provided in Enclosure 1 of the LAR) reflect the redundant or absolute minimum electrical power source/subsystem required to be operable to support the safety functions necessary to mitigate postulated DBAs, safely shut down the reactor, and maintain the reactor in a safe shutdown condition. In addition, the staff

reviewed the proposed RMA examples for reasonable assurance that these RMAs are appropriate to monitor and control risk for the condition applicable to the proposed TS change.

TS 3.8.1, Condition A "One offsite circuit inoperable," Action A.2

The licensee has proposed to apply the RICT program to TS 3.8.1, Condition A, "One offsite circuit inoperable," Action A.2 to extend the CT from the current value of 72 hours to 30 days maximum per the RICT program if risk remains within the guidance of NEI 06-09-A. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of multiple RMAs that may be considered during a RICT program entry to reduce the risk impact and ensure adequate DID. In particular, Enclosure 12 of the LAR listed the example RMAs which are likely to be implemented during TS action 3.8.1.A, "One offsite circuit inoperable."

TS 3.8.1, Condition B "One required DG inoperable," Action B.4

The licensee has proposed to apply the RICT program to TS 3.8.1, Condition B, "One required DG inoperable," Action B.4 to extend the CT from the current value of 72 hours to 30 days maximum per the RICT program for the Division 3 DG; and to extend the CT from the current value of 14 days to 30 days maximum per the RICT program for the Division 1 or 2 DG, if the risk remains within limits of the NEI 06-09-A guidance. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of multiple RMAs that may be considered during a RICT program entry to reduce the risk impact and ensure adequate DID. In particular, Enclosure 12 of the LAR listed the example RMAs which are likely to be implemented during TS action 3.8.1.B, "One required DG inoperable."

TS 3.8.1, Condition C "Two offsite circuits inoperable," Action C.2

The licensee has proposed to apply the RICT program to TS 3.8.1, Condition C, "Two offsite circuits inoperable," Action C.2 to extend the CT from the current value of 24 hours to 30 days maximum per the RICT program, if risk remains within the limits of the NEI 06-09-A guidance. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of RMAs that may be considered during a RICT program entry to reduce the risk impact and ensure adequate DID.

In its supplement dated November 24, 2020, the licensee provided the example RMAs which are likely to be implemented during RICT of TS 3.8.1, Condition C, "Two offsite circuits inoperable."

TS 3.8.1, Condition D "One required offsite circuit inoperable AND One required DG inoperable," Action D.1 or Action D.2

The licensee has proposed to apply the RICT program to TS 3.8.1, Condition D, "One required offsite circuit inoperable AND One required DG inoperable," Action D.1 or Action D.2 to extend the CT from the current value of 12 hours to 30 days maximum per the RICT program, if the risk remains within the limits of the NEI 06-09-A guidance. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of RMAs that may be considered during a RICT program entry to reduce the risk impact and ensure adequate DID. In particular, Enclosure 12 of the LAR listed the example RMAs which are likely to be implemented during TS action 3.8.1, Condition D, "One required offsite circuit inoperable AND One required DG inoperable."

3.2.2.1.3 DC Sources – Operating (TS 3.8.4)

Description of the DC Sources

CPS USAR Section 8, and TS Bases B.3.8.4 describe that each Division 1, 2, 3, and 4, battery has adequate storage capacity to meet the load duty cycle(s) discussed in the USAR, Section 8.3.2. Each DC battery subsystem is located in an area separated physically and electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems such as batteries, battery chargers, or distribution panels.

The batteries for a DC electrical power subsystem are sized to produce the required capacity at 80 percent of nameplate rating. The minimum design voltage limit is 105 volt (V). The battery cells are flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 120 V for a 58-cell battery (i.e., cell voltage of 2.065 volts per cell). The nominal float voltage of 2.22 Vpc corresponds to a total float voltage output of 128.8 V for a 58-cell battery. Each battery charger of Division 1, 2, 3, and 4, DC electrical power subsystems has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger has sufficient excess capacity to restore the battery bank from the design minimum charge to its fully charged state within 12 hours while supplying normal steady-state loads.

TS 3.8.4 - Changes Relating to DC Power – Operating

See Section 2.2 of this SE for a detailed view of TS changes.

Evaluation of TS Changes Relating to DC Sources - Operating

For each change identified below, the NRC staff reviewed the information pertaining to the proposed TS change in the LAR, the USAR, and applicable TS LCO and TS Bases to verify that the capability of the affected electrical power systems to perform their safety functions (assuming no additional failures) is maintained. To achieve that objective, the NRC staff verified that the proposed TS condition's design success criteria (as provided in Enclosure 1 of the LAR) reflect the redundant or absolute minimum electrical power source/subsystem required to be operable to support the safety functions necessary to mitigate postulated DBAs, safely shut down the reactor, and maintain the reactor in a safe shutdown condition. In addition, the staff reviewed the proposed RMA examples for reasonable assurance that these RMAs are appropriate to monitor and control risk for the condition applicable to the proposed TS change.

TS 3.8.4, Condition A "One battery charger on Division 1 or 2 inoperable," Action A.3

The licensee has proposed to apply the RICT program to TS 3.8.4, Condition A, "One battery charger on Division 1 or 2 inoperable," Action A.3 to extend the CT from the current value of 7 days to 30 days maximum per the RICT program, if the risk remains within the guidance of NEI 06-09-A. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of RMAs that may be considered during a RICT program entry to reduce the risk impact and ensure adequate DID. In particular, Enclosure 12 of the LAR listed the example RMAs which are likely to be implemented during TS action 3.8.4.A, "One battery charger on Division 1 or 2 inoperable."

Considering that the CT extension will be implemented if the risk values are in accordance with the NEI 06-09-A guidance, and that additional RMAs will be implemented, the NRC staff finds that the plant will have adequate DID. Therefore, the NRC staff finds the application of the RICT program to TS 3.8.4, Condition A, "One battery charger on Division 1 or 2 inoperable," Action A.3, acceptable.

TS 3.8.4, Condition B "One battery on Division 1 or 2 inoperable," Action B.1

The licensee has proposed to apply the RICT program to TS 3.8.4, Condition B, "One battery on Division 1 or 2 inoperable," Action B.1 to extend the CT from the current value of 2 hours to 30 days maximum per the RICT program, if risk remains within the guidance of NEI 06-09-A. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of RMAs that are likely to implemented during a RICT program entry to reduce the risk impact and ensure adequate DID.

In the supplement dated November 24, 2020, the licensee provided the example RMAs which are likely to be implemented during RICT of TS 3.8.4, Condition B, "One battery on Division 1 or 2 inoperable."

(c) TS 3.8.4, Condition C "Division 1 or 2 DC electrical power subsystem inoperable for reasons other than Condition A or B," Action C.1

The licensee has proposed to apply the RICT program to TS 3.8.4, Condition C, "Division 1 or 2 DC electrical power subsystem inoperable for reasons other than Condition A or B," Action C.1 to extend the CT from the current value of 2 hours to 30 days maximum per the RICT program, if risk remains within the guidance of NEI 06-09-A. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of RMAs that are likely to be implemented during a RICT program entry to reduce the risk impact and ensure adequate DID.

In the supplement dated November 24, 2020, , the licensee provided the example RMAs which will be implemented during RICT of TS 3.8.4, Condition C, "Division 1 or 2 DC electrical power subsystem inoperable for reasons other than Condition A or B."

3.2.2.1.4 Inverters – Operating (TS 3.8.7)

Description of the Inverters

CPS USAR, Section 8, and TS Bases B.3.8.7, describe that the inverters are the preferred source of power for the uninterruptible AC buses and the RPS solenoid buses because of the stability and reliability they achieve. There is one inverter per uninterruptible AC bus (comprising a total of four divisional inverters) and one inverter per RPS solenoid bus (comprising a total of two RPS solenoid bus inverters). The function of the inverter is to provide AC electrical power to these buses. The inverters are powered from both AC and DC sources. The DC source provides an uninterruptible power source for the instrumentation and controls (I&C) for the RPS, the ECCS initiation, miscellaneous isolations, and the RPS and main steam isolation valve (MSIV) solenoids.

The divisional inverters contain a solid-state transfer switch to automatically transfer to an alternate source if the inverter detects abnormal conditions, such as an internal inverter component failure or for handling fault clearing or inrush current demands. The transfer of the

divisional inverters to their alternate source will occur if the alternate source is either energized or deenergized.

TS 3.8.7 - Changes Relating to Inverters – Operating

See Section 2.2 of this SE for a detailed view of TS changes.

Staff Evaluations of TS Changes Relating to Inverters - Operating

For each change identified below, the NRC staff reviewed the information pertaining to the proposed TS change in the LAR, the USAR, and applicable TS LCO and TS Bases to verify that the capability of the affected electrical power systems to perform their safety functions (assuming no additional failures) is maintained. To achieve that objective, the NRC staff verified that the proposed TS condition's design success criteria (as provided in Enclosure 1 of the LAR) reflect the redundant or absolute minimum electrical power source/subsystem required to be operable to support the safety functions necessary to mitigate postulated DBAs, safely shut down the reactor, and maintain the reactor in a safe shutdown condition. In addition, the staff reviewed the proposed RMA examples for reasonable assurance that these RMAs are appropriate to monitor and control risk for the condition applicable to the proposed TS change.

TS 3.8.7, Condition A "Division 1 or 2 inverter inoperable," Action A.1

The licensee has proposed to apply the RICT program to TS 3.8.7, "Division 1 or 2 inverter inoperable," Action A.1 to extend the CT from the current value of 7 days to 30 days maximum per the RICT program, if risk remains within the guidance of NEI 06-09-A. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of RMAs that are likely to be implemented during a RICT program entry to reduce the risk impact and ensure adequate DID.

In its letter dated November 24, 2020, the licensee provided the example RMAs which are likely to be implemented during RICT of TS 3.8.7, Condition A "Division 1 or 2 inverter inoperable."

3.2.2.1.5 Distribution Systems – Operating (TS 3.8.9)

Description of the Distribution Systems

CPS TS Bases B.3.8.9 describes that the onsite Class 1E AC and DC electrical power distribution systems are divided into three independent AC, four independent DC, and four divisional uninterruptible AC bus electrical power distribution subsystems.

The primary AC distribution system consists of each 4.16 kV ESF bus that has at least one separate and independent offsite source of power, as well as a dedicated onsite DG source. Each 4.16 kV ESF bus is normally connected to a preferred source. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 4.16 kV ESF buses. The DC distribution system provides control power for the 4.16 kV breakers which is supplied from the Class 1E batteries.

The secondary plant AC distribution system includes 480 V ESF load centers and associated loads, motor control centers, and transformers. The 120 V uninterruptible AC buses are arranged in four divisions and are normally powered from an inverter supplied with DC power. The alternate power supply for the uninterruptible AC buses is a Class 1E constant voltage

source transformer powered from the same division as the associated inverter. There are four independent 125 vpc (volt per cell) electrical power distribution subsystems.

TS 3.8.9 - Changes Relating to Distribution Systems – Operating

See Section 2.2 of this SE for a detailed view of TS changes.

Evaluation of TS Changes Relating to Inverters - Operating

For each change identified below, the NRC staff reviewed the information pertaining to the proposed TS change in the LAR, the USAR, and applicable TS LCO and TS Bases to verify that the capability of the affected electrical power systems to perform their safety functions (assuming no additional failures) is maintained. To achieve that objective, the NRC staff verified that the proposed TS condition's design success criteria (as provided in Enclosure 1 of the LAR) reflect the redundant or absolute minimum electrical power source/subsystem required to be operable to support the safety functions necessary to mitigate postulated DBAs, safely shut down the reactor, and maintain the reactor in a safe shutdown condition. In addition, the staff reviewed the proposed RMA examples for reasonable assurance that these RMAs are appropriate to monitor and control risk for the condition applicable to the proposed TS change.

TS 3.8.9, Condition A "One or more Division 1 or 2 AC electrical power distribution subsystems inoperable," Action A.1

The licensee has proposed to apply the RICT program to TS 3.8.9, Condition A, "One or more Division 1 or 2 AC electrical power distribution subsystems inoperable," Action A.1 to extend the CT from the current value of 8 hours to 30 days maximum per the RICT program, provided no loss of function occurs and if risk remains within the guidance of NEI 06-09-A. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of RMAs that are likely to be implemented during a RICT program entry to reduce the risk impact and ensure adequate DID.

In its letter dated November 24, 2020, the licensee provided the example RMAs which will be implemented during RICT of TS 3.8.9, Condition A, "One or more Division 1 or 2 AC electrical power distribution subsystems inoperable."

TS 3.8.9, Condition B "One or more Division 1 or 2 uninterruptible AC bus distribution subsystems inoperable," Action B.1

The licensee has proposed to apply the RICT program to TS 3.8.9, Condition B, "One or more Division 1 or 2 uninterruptible AC bus distribution subsystems inoperable," Action B.1, to extend the CT from the current value of 8 hours to 30 days maximum per the RICT program, provided no loss of function occurs and if risk remains within the guidance of NEI 06-09-A. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of RMAs that are likely to be considered during a RICT program entry to reduce the risk impact and ensure adequate DID.

In its letter dated November 24, 2020, the licensee provided the example RMAs which are likely to be implemented during RICT of TS 3.8.9, Condition B, "One or more Division 1 or 2 uninterruptible AC bus distribution subsystems inoperable."

<u>TS 3.8.9, Condition C "One or more Division 1 or 2 DC electrical distribution subsystems inoperable," Action C.1</u>

The licensee has proposed to apply the RICT program to TS 3.8.9, Condition C, "One or more Division 1 or 2 DC electrical distribution subsystems inoperable," Action C.1, to extend the CT from the current value of 2 hours to 30 days maximum per the RICT program, provided no loss of function occurs and if risk remains within the guidance of NEI 06-09-A. In the LAR, Enclosure 12, "Risk Management Action (RMA) Examples," the licensee provided examples of RMAs that are likely to be considered during a RICT program entry to reduce the risk impact and ensure adequate DID.

In the supplement dated November 24, 2020, the licensee provided the example RMAs which are likely to be implemented during RICT of TS 3.8.9, Condition C, "One or more Division 1 or 2 DC electrical distribution subsystems inoperable."

3.2.2.1.6 Electrical Power Systems Evaluation Conclusion

The NRC staff finds that while the redundancy is not maintained (e.g., one train of a two-train system is inoperable), the CT extensions in accordance with the RICT program are acceptable because: (1) the capability of the systems to perform their safety functions (assuming no additional failures) is maintained thereby maintaining DID, and (2) the licensee's demonstration of identifying and implementing compensatory measures or RMAs, in accordance with the RICT program, are appropriate to monitor and control risk.

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

The licensee has requested to use the RICT program to extend the existing CT for the following TS conditions. The NRC staff's evaluation of the proposed changes considered a number of potential plant conditions allowed by the new TSs and considered what redundant or diverse means were available to assist the licensee in responding to various plant conditions. The plant conditions evaluated are discussed in more detail below. See Section 2.2 for a detailed view of TS changes.

- LCO 3.3.1.1 Reactor Protection System (RPS) Instrumentation
- LCO 3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation
- LCO 3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation
- LCO 3.3.5.3 Reactor Core Isolation Cooling (RCIC) System Instrumentation
- LCO 3.3.6.1 Primary Containment and Drywell Isolation Instrumentation
- LCO 3.3.6.3 Residual Heat Removal (RHR) Containment Spray System Instrumentation
- LCO 3.3.6.4 Suppression Pool Makeup (SPMU) System Instrumentation
- LCO 3.3.6.5 Relief and Low-Low Set (LLS) Instrumentation
- LCO 3.3.8.1 Loss of Power (LOP) Instrumentation

Attachment 5 of the LAR provided information supporting the evaluation of the redundancy and diversity of instrumentation included in the TS changes proposed. The information provided in Attachment 5 of the LAR was evaluated as described in the subsections below.

The NRC staff followed the guidance formulated in RG 1.174 and elaborated upon in RG 1.177, to assess the proposed changes' consistency with DID criteria. The applicable DID criteria to the affected CPS I&C systems are:

- Over-reliance on programmatic activities as compensatory measures associated with the change in the LB is avoided.
- System redundancy, independence, and diversity are maintained commensurate with the expected frequency and consequences of challenges to the system (e.g., there are no risk outliers).
- Defenses against potential CCF are maintained and the potential for the introduction of new common cause failure mechanisms is assessed.
- The intent of the plant's design criteria is maintained.

The licensee confirmed, and NRC staff verified that, in accordance with the CPS USAR in all applicable operating modes, the affected protective feature would perform its intended function by ensuring the ability to detect and mitigate the associated event or accident when the CT of a channel is extended. The RICT program is not being applied to shutdown modes. Therefore, the NRC staff concludes that the intent of the plant's design criteria for the I&C functions identified in the amendment are maintained.

The NRC staff finds that while in an LCO condition, the redundancy of the function will be temporarily relaxed, and consequently the system reliability will be degraded accordingly. The NRC staff examined the design information from the CPS USAR and the risk-informed LCO conditions for the affected I&C functions. Based on this information, the NRC staff confirmed that under any given DBA evaluated in the CPS USAR, the affected I&C protective features maintains adequate DID by either necessary redundancy (e.g., at least one redundant channel) and/or necessary diversity (e.g., at least one alternative safety feature).

The licensee stated in the LAR that the proposed changes do not alter CPS I&C system designs. Consequently, the NRC staff concludes that the proposed changes do not alter the ways in which the CPS I&C systems fail, and do not introduce new CCF modes, and that system independence is maintained. The NRC staff finds that some proposed changes reduce the level of redundancy of the affected I&C systems, and this reduction may reduce the level of defense against some CCFs; however, the NRC staff finds, as described below, that such reduction in redundancy and defense against common cause failures are acceptable due to existing diverse means available to maintain adequate DID against a potential single failure during the RICT for the CPS I&C systems.

The following sections summarize the NRC staff's findings with respect to the DID principle for the functions identified in the LAR by identifying associated diverse means that maintain adequate DID against potential single failure during an RICT for the CPS I&C systems.

3.2.2.2.1 LCO 3.3.1.1 Reactor Program System (RPS) Instrumentation

The LAR states that the RPS is a fail-safe system design (de-energizes to trip) and is comprised of four independent trip logic divisions as described in USAR, Section 7.2. In addition to RPS de-energizing the scram pilot valves and energizing the backup scram valves, CPS has redundant and diverse methods of shutting down the reactor in the unlikely event that the RPS does not SCRAM the reactor (anticipated transient without scram (ATWS), alternate rod

insertion (ARI), recirculation pump trip (RPT) breakers, and the standby liquid control system (SLCS)).

The logic trip arrangement, redundancy, and diverse inputs causing a trip of the RPS are discussed and shown in USAR Section 7.2 and Figures 7.2-2 thru 7.2-4, CPS TS LCO 3.3.3.1, Table 3.3.1.1-1 and Bases B3.3.1.1 and reflected in Attachment 5 of the LAR.

The NRC staff finds that the RPS design has sufficient redundancy, diversity, and DID to protect against common cause failures and potential failure during the RICT for the CPS I&C systems and does not rely on manual actions as the only diverse means; therefore, there is no over-reliance on programmatic activities as compensatory measures.

3.2.2.2.2 LCO 3.3.4.1 End of Cycle-Recirculation Pump Trip (EOC-RPT) Instrumentation

The LAR states that the EOC-RPT instrumentation initiates a recirculation pump trip (RPT) to reduce the peak reactor pressure and power resulting from turbine trip or generator load rejection transients to provide additional margin to core thermal MCPR Safety Limits.

The logic trip arrangement, redundancy, and diverse inputs causing a trip of the EOC-RPT are discussed and shown in USAR Section 7.6.1.8, CPS TS LCO 3.3.4.1 and Bases B3.3.4.1 and reflected in Attachment 5 of the LAR.

The NRC staff finds that the EOC-RPS design has sufficient redundancy, diversity, and DID to protect against common cause failures and potential single failure during the RICT for the CPS I&C systems and does not rely on manual actions as the only diverse means; therefore, there is no over-reliance on programmatic activities as compensatory measures.

3.2.2.2.3 LCO 3.3.5.1 ECCS Instrumentation

The LAR states that the purpose of the ECCS instrumentation is to initiate appropriate responses from the systems to ensure that fuel is adequately cooled in the event of a design basis accident or transient. The ECCS instrumentation actuates low-pressure core spray (LPCS), LPCI, high-pressure core spray (HPCS), ADS, and the DGs.

For instrumentation that has the potential for a configuration in which trip capability is not maintained, a Note was added to the CT which prohibits applying a RICT when trip capability is not maintained.

The logic trip arrangement, redundancy, and diverse inputs causing a trip of the ECCS are discussed and shown in USAR Sections 5.2.2, 6.3, and 7.3, CPS TS LCO 3.3.5.1, Table 3.3.5.1-1, and reflected in Attachment 5 of the LAR.

The NRC staff finds that the ECCS design has sufficient redundancy, diversity, and DID to protect against CCFs and potential single failure during the RICT for the CPS I&C systems and does not rely on manual actions as the only diverse means; therefore, there is no over-reliance on programmatic activities as compensatory measures .

3.2.2.2.4 LCO 3.3.5.3 Reactor Core Isolation Cooling (RCIC) System

The LAR states that the RCIC system instrumentation is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser)

and normal coolant makeup flow from the reactor feedwater system is unavailable, such that initiation of the low pressure ECCS pumps does not occur.

For instrumentation that has the potential for a configuration in which trip capability is not maintained, a Note was added to the CT which prohibits applying a RICT when trip capability is not maintained. The logic trip arrangement, redundancy, and diverse inputs causing a trip of the RCIC system are discussed and shown in USAR Section 7.4.1.1.3.2, CPS TS LCO 3.3.5.3, Table 3.3.5.3-1 and reflected in Attachment 5 of the LAR.

The NRC staff finds that the RCIC system design has sufficient redundancy, diversity, and DID to protect against common cause failures and potential single failure during the RICT for the CPS I&C systems and does not rely on manual actions as the only diverse means; therefore, there is no over-reliance on programmatic activities as compensatory measures.

3.2.2.2.5 LCO 3.3.6.1 Primary Containment and Drywell Isolation Instrumentation

The LAR states that the primary containment and drywell isolation instrumentation automatically initiates closure of appropriate primary containment isolation valves (PCIVs) and drywell isolation valves. The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated DBAs. Functional diversity is provided by monitoring a wide range of independent parameters.

For instrumentation that has the potential for a configuration in which trip capability is not maintained, a Note was added to the CT which prohibits applying a RICT when trip capability is not maintained.

The logic trip arrangement, redundancy, and diverse inputs causing a trip of the primary containment and drywell isolation instrumentation are discussed and shown in USAR Section 7.3.1.1.2, CPS TS LCO 3.3.6.1, Table 3.3.6.1-1, and reflected in Attachment 5 of the LAR.

The NRC staff finds that the primary containment and drywell isolation instrumentation design has sufficient redundancy, diversity, and DID to protect against common cause failures and potential single failure during the RICT for the CPS I&C systems and does not rely on manual actions as the only diverse means; therefore, there is no over-reliance on programmatic activities as compensatory measures.

3.2.2.2.6 LCO 3.3.6.3 Residual Heat Removal (RHR) Containment Spray System (CSS) Instrumentation

The LAR states that the RHR CSS is an operating mode of the RHR system that is initiated to condense steam in the containment atmosphere. This ensures that containment pressure is maintained within its limits following a LOCA.

For instrumentation that has the potential for a configuration in which trip capability is not maintained, a Note was added to the CT which prohibits applying a RICT when trip capability is not maintained.

The logic trip arrangement, redundancy, and diverse, inputs causing a trip of the RHR CSS are discussed and shown in USAR Section 7.3.1.1.4, CPS TS LCO 3.3.6.3, Table 3.3.6.3-1, and reflected in Attachment 5 of the LAR.

The NRC staff finds that the RHR CSS design has sufficient redundancy, diversity, and DID to protect against common cause failures and potential single failure during the RICT for the CPS I&C systems and does not rely on manual actions as the only diverse means; therefore, there is no over-reliance on programmatic activities as compensatory measures .

3.2.2.2.7 LCO 3.3.6.4 Suppression Pool Makeup (SPMU) System Instrumentation

The LAR states that the SPMU system provides water from the upper containment pool to the suppression pool, by gravity flow, after a LOCA to ensure that primary containment temperature and pressure design limits are met.

For instrumentation that has the potential for a configuration in which trip capability is not maintained, a Note was added to the CT which prohibits applying a RICT when trip capability is not maintained.

The logic trip arrangement, redundancy, and diverse, inputs causing a trip of the SPMU system, are discussed and shown in USAR Section 7.3.1.1.10, CPS TS LCO 3.3.6.4, Table 3.3.6.4-1, and reflected in Attachment 5 of the LAR.

The NRC staff finds that the SPMU design has sufficient redundancy, diversity, and DID to protect against CCFs and potential single failure during the RICT for the CPS I&C systems and does not rely on manual actions as the only diverse means; therefore, there is no over-reliance on programmatic activities as compensatory measures.

3.2.2.2.8 LCO 3.3.6.5 Relief and Low Low Set (LLS) Instrumentation

The LAR states that the safety relief valves (SRVs) prevent overpressurization of the nuclear steam system. Instrumentation is provided to support two modes (in addition to the ADS mode of operation for selected valves) of SRV operation.

The logic trip arrangement, redundancy, and diverse, inputs causing a trip of the LLS instrumentation are discussed and shown in USAR Section 7.3.1.1.1.4, 7.3.1.1.1.4.2, CPS TS LCO 3.3.6.5 and are reflected in Attachment 5 of the LAR.

The NRC staff finds that the LLC design has sufficient redundancy, diversity, and DID to protect against common cause failures and potential single failure during the RICT for the CPS I&C systems and does not rely on manual actions as the only diverse means; therefore, there is no over-reliance on programmatic activities as compensatory measures.

3.2.2.2.9 LCO 3.3.8.1 Loss of Power (LOP) Instrumentation

The electrical aspects of the loss of power instrumentation is described in Section 3.2.2.1.1, "Loss of Power (LOP) Instrumentation (TS 3.3.8.1)," above. The defense-in-depth aspects of concern to instrumentation and controls were evaluated but this section does not repeat the detailed description of electrical and loss of power instrumentation descriptions above.

For instrumentation that has the potential for a configuration in which trip capability is not maintained, a Note was added to the CT which prohibits applying a RICT when trip capability is not maintained.

The logic trip arrangement, redundancy, and diverse, inputs causing a trip of the LOP instrumentation are discussed and shown in USAR Section 8.3.1.1.2, CPS LCO 3.3.8-1, TS Table 3.3.8.1-1, and reflected in attachment 5 of the LAR.

The NRC staff finds that the LOP design has sufficient redundancy, diversity, and DID to protect against common cause failures and potential single failure during the RICT for the CPS I&C systems and does not rely on manual actions as the only diverse means; therefore, there is no over-reliance of programmatic activities as compensatory measures .

3.2.2.2.10 Instrumentation and Control (I&C) Evaluation Conclusion

Since the licensee did not propose any changes to the design basis, the independency and the fail-safe principle remain unchanged. The licensee stated in the LAR that the proposed changes did not include any TS loss of function conditions. However, it is recognized that while in an ACTION statement, redundancy of the given protective feature will be temporarily reduced, and, accordingly, the system reliability will be reduced. In the LAR, the licensee stated in the description of proposed changes to the I&C systems that at least one redundant or diverse means (e.g., other automatic features or manual action) to accomplish the safety functions (e.g., reactor trip, safety injection, or containment isolation) remain available during the use of the RICT. The NRC staff reviewed the licensee's proposed TS changes to assess the availability of the redundant or diverse means to accomplish the safety function(s). The NRC staff finds that the availability of the redundant or diverse protective features provide sufficient DID to accomplish the safety functions, allowing for the extension of CTs in accordance with the RICT program. The NRC staff finds that the licensee's proposed RICT program for the identified I&C systems is in compliance with 10 CFR 50.36(b).

The NRC staff reviewed the licensee's proposed TS changes and supporting documentation. The staff finds that while the I&C redundancy is reduced, the CT extensions implemented in accordance with the RICT program are acceptable because: (1) the capability of the I&C systems to perform their safety functions is maintained, (2) redundant or diverse means to accomplish the safety functions exist, and (3) the licensee will identify and implement risk management actions to monitor and control risk in accordance with the RICT program.

3.2.2.3 Evaluation of Balance of Plant Components

The regulation in 10 CFR 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 is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the TSs. In Attachment 2, the licensee proposed a Note, "Not applicable if loss of function," for TS LCO conditions to prohibit entering a RICT during a loss of function condition. However, the proposed change to TS LCO 3.7.6 (main turbine bypass system), Condition A, (requirements of LCO not met) appears to include a TS loss of function and has no such Note. Enclosure 1 to the LAR, Table E1-1, indicates that the design basis success criteria for TS 3.7.6.A requires all six turbine bypass valves to be operable, indicating loss of function with a failure of a single valve. Therefore, the NRC staff asked the licensee to justify that the proposed RICT for TS 3.7.6.A did not include a loss of function.

In its response, dated November 24, 2020, the licensee stated that the purpose of LCO 3.7.6 is to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, which is accomplished by either: (1) the main turbine bypass system, or (2) by limiting reactor power and implementing designated

thermal limits in accordance with the cycle-dependent COLR and modifications to the MCPR limits and LHGR limits. The cycle-specific analyses as documented in the COLR evaluate different combinations of turbine bypass valves (TBVs) that are out-of-service (OOS). The COLR for the current operating cycle supports full power operation with one TBV OOS, but also considers different conditions including all TBVs OOS. As a result, the LCO function of limiting peak pressure in the main steam lines and maintaining reactor pressure within acceptable limits continues to be met under the conditions analyzed in the cycle-specific analyses, which includes all TPVs OOS. Based on the number of TBVs out of service, the correct COLR thermal limit set is selected. By using the correct thermal limit, the analyzed design function of the TBVs will be met and no loss of function results.

The NRC staff finds that the licensee's response clarifies that if a turbine bypass valve fails, LCO 3.7.6 function is maintained by limiting reactor power and implementing designated thermal limits in accordance with the cycle-dependent COLR and modifications to the MCPR limits and LHGR limits. Therefore, the staff finds that the licensee's response demonstrates that no loss of function exists.

3.2.2.4 Key Principle 2: Conclusions

The LAR proposes to modify the TS requirements to permit extending selected CTs using the RICT program in accordance with NEI 06-09-A. 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 provided that the licensee identifies and implements RMAs in accordance with the RICT program during the extended CT.

Quantitative risk analysis, qualitative considerations including compensatory measures, and retaining the current CT for loss of all trains of a required system, assure that DID is maintained to assure adequate protection of public health and safety. The NRC staff finds that the proposed changes are consistent with the DID philosophy because:

- System redundancy (with the exceptions discussed above), independence, and diversity commensurate with the expected frequency and consequences of challenges to the system is preserved.

- Adequate capability of design features without an overreliance on programmatic activities as compensatory measures is preserved.

- The intent of the plant's design criteria continues to be met.

Therefore, the NRC staff finds that the proposed change to modify the TS requirements to permit extending selected CTs using the RICT program in accordance with NEI 06-09-A meets the second key safety principle of RG 1.177 and is, therefore, acceptable. Additionally, the NRC staff concludes that the change is consistent with the DID philosophy as described in RG 1.174.

3.2.3 Key Principle 3: Evaluation of Safety Margins

Section 2.2.2 of RG 1.177, Revision 1, 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 (FSAR) 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. Acceptance criteria for operability of equipment are not changed and use of the RICT only when the system(s) retain(s) the capability to perform the applicable safety function(s) ensure that the current safety margins are retained. 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. The reduced but available functionality may support a further increase in the CT consistent with available safety margin. The specified safety function is still being met by the operable train and therefore requires no evaluation of PRA functionality to meet the design basis success criteria.

3.2.3.1 Key Principle 3: Conclusions

The NRC staff finds that the design-basis analyses for CPS remain applicable. Although the licensee will be able to have design-basis equipment out-of-service longer than the current TS allow and the likelihood of successful fulfillment of the function will be decreased when redundant train(s) are not available, the capability to fulfill the function will be retained when the available equipment functions as designed. Any increase in unavailability because less equipment is available for a longer time is included in the RICT evaluation and is expected to be insignificant given the relatively short duration of the extended CT. Therefore, sufficient safety margins are maintained with the implementation of the RICT program. The NRC staff concludes that the proposed changes meet the third key safety principle of RG 1.177 and are acceptable.

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

TS Section 5.5.17 "Risk Informed Completion Time Program," states that the RICT "must be implemented in accordance with NEI 06-09, Revision 0,"Risk-Managed Technical Specification (RMTS) Guidelines."

NEI 06-09 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 Chapter 16.1 of the SRP, RG 1.177, and RG 1.174, Revision 1. This approach addresses the calculated change in risk as measured by the change in delta core damage frequency (ΔCDF) and delta large early release frequency (ΔLERF), as well as the incremental conditional core damage probability and incremental conditional large early release probability; 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, as discussed below. The NRC staff evaluated the licensee's proposed changes against the three-tiered approach in RG 1.177, Revision 1, for the licensee's evaluation of the risk associated with a proposed TS CT change. The results of the 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) the technical 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.

3.2.4.1.1 PRA Technical Acceptability

Scope of PRA

RG 1.174 states that the scope, level of detail, and technical adequacy of the PRA are to be commensurate with the application for which it is intended and the role the PRA results play in the integrated decision process. The NRC's SE for NEI 06-09 states that the PRA models should conform to the guidance in RG 1.200, Revision 1, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," January 2017 (Reference 13). The current version is RG 1.200, Revision 2, which clarifies the current applicable American Society of Mechanical Engineers/American Nuclear Society (ASME/ANS) PRA Standard is ASME/ANS RA-Sa-2009, "Addenda to ASME RA-S-2008, Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications" (Reference 14). 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. According to the LAR, the proposed RICT program is only applicable to operational conditions (or Modes) 1 and 2, therefore, risk evaluations for Modes 3, 4, and 5, are not relevant to the proposed change.

The NRC staff evaluated the PRA acceptability information provided by the licensee in Enclosure 2 of its submittal, 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, as described in Section 3.2.4.1.2 of this SE, as insignificant contributors to RICT calculations. The CPS PRA model with modifications is used as the CRMP model as described in Section 3.2.4.1.2 of this SE. In addition, the licensee provided a bounding estimate of the seismic CDF and LERF and included those CDF and LERF values in the change-in-risk used to calculate RICTs consistent with the guidance in NEI 06-09-A

3.2.4.1.2 Evaluation of PRA Acceptability for Internal Events and Internal Fires

Internal Events PRA (IEPRA) (Includes Internal Flooding)

The CPS PRA is comprised of a full-power, Level 1, IEPRA which evaluates the CDF and LERF risk metrics. The licensee discussed in Enclosure 2 of the LAR that the IEPRA (includes

internal floods) model had been assessed against RG 1.200, Revision 2. The NRC staff evaluated the scope of the PRA including: (1) peer-review history and results, (2) the Appendix X, independent assessment process, (3) credit for FLEX in the PRA, and (4) assessment of key assumptions and key sources of uncertainty. The NRC staff also performed a review of the remaining open facts and observations (F&Os) for the IEPRA, along with the dispositions provided in Enclosure 2 of the LAR and its supplements.

For both the CPS 10 CFR 50.69 (Reference 16) and the CPS TSTF-505 risk-informed applications, the PRA models were reviewed against the current PRA Standard across all technical elements at Capability Category (CC) II. Therefore, the staff's review of the IEPRA (includes internal floods) model for PRA acceptability was performed concurrently with the CPS 10 CFR 50.69 application. A detailed staff evaluation of the IEPRA peer review history is provided in the NRC staff's safety evaluation dated May 19, 2021 (Reference 17). The NRC staff's evaluation of the key assumptions and key sources of uncertainty specific to the TSTF-505 application are provided below.

Based on its review, and applicable precedent provided in the issuance of the SE for CPS's adoption of 10 CFR 50.69, the NRC staff finds that the IEPRA has been peer reviewed consistent with RG 1.200, Revision 2; F&Os were closed consistent with Appendix X guidance of NEI 07-12, Revision 0, "Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines, Draft Version H," November 2008 (Reference 18), as accepted, with conditions by the NRC staff; and any remaining open F&Os have been appropriately assessed for impact on the RICT program. Therefore, the NRC staff concludes that the internal events PRA, including internal flooding, is acceptable for use in the RICT program.

Internal Fire Events PRA

The NRC staff review of the CPS fire PRA was based on the results of a full-scope peer review of the fire PRA and two F&Os closure reviews described in LAR Enclosure 2. The full-scope peer review of the fire PRA was performed in April 2018 using the NEI 07-12 process and the guidance in the ASME/ANS RA-Sa-2009 PRA Standard and RG 1.200, Revision 2.

The licensee stated that the 2018 fire PRA peer review F&Os were addressed in subsequent fire PRA updates and the resolutions to the F&Os were reviewed by independent review teams in two separate F&O Closures (December 2018 and November 2019) that included fire PRA F&Os. The second CPS fire PRA F&O closure review performed in November 2019 resulted in closing all finding level F&Os.

Extensive and detailed reviews of fire PRAs undertaken in support of LARs to transition to National Fire Protection Association-805 determined that implementation of some of the complex fire PRA methods often used non-conservative and over-simplified assumptions to apply the method to specific plant configurations. Accordingly, the NRC staff requested the following fire PRA information that did not appear to be addressed by other docketed information.

On October 27, 2020 (Reference 19), the NRC staff requested information about the use of reduced transient fire heat release rates (HRRs) below those prescribed in NUREG/CR-6850, "EPRI/NRC Fire PRA Methodology for Nuclear Power Facilities," September 2005 (Reference 20), and NUREG/CR-6850, Supplement 1, "Fire Probabilistic Risk Assessment Methods Enhancement," September 2010 (Reference 21), and justification if reduced HRRs were used.

Key factors for justifying reduced HRRs below those prescribed in NUREG/CR-6850 are discussed in guidance provided in the June 21, 2012, letter from Joseph Giitter, NRC, to Biff Bradley, NEI (Reference 22).

In its letter dated November 24, 2020, the licensee explained that for the cable spreading rooms (CSRs), three potential transient fire sizes were assessed (i.e., 60 kW (kilowatt), 145 kW, and 317 kW). The licensee stated that the cited results of fire tests reported in NUREG/CR-6850 for 60 kW, 145 kW, and 317 kW, fires were considered representative for spaces in the CSRs. The licensee explained that detailed fire modeling was performed for each of the three fire sizes and that the results of the fire modeling were averaged, and the average probability of fire damage was used in the fire PRA (i.e., product of the Severity Factor and Non-Suppression Probability). The licensee justified the use of a reduced HRR by addressing factors described in the NRC letter dated June 21, 2012.

The licensee cited its transient combustible material control procedure and explained that Transient Combustible Permits (TCPs) are required and reviewed by the Fire Marshall and procedures provide specific guidance for storage and transporting combustible materials in Transient Combustible Free Zones. The licensee stated that per procedure, combustible materials are limited in Transient Combustible Free Zones to materials required to support work activity and are immediately removed from the area following completion of the task. The licensee presented a list of the TCPs from the last 4 years for the CSRs showing that the increase in combustible loading in British Thermal Units (BTUs) compared to the BTUs for cable loading for each TCP is only about 1% or lower. The licensee also showed that over this same time period (i.e., since 2016), there have been no compliance issues or violations associated with the use of transient combustibles in the CSRs.

Based on its review, the NRC staff finds the licensee's use of reduced HRRs in the CSRs to be acceptable and consistent with NRC guidance because: (1) the reduced HRRs used are based on the results of fire tests reported in NUREG/CR-6850 that represent fires that could happen in the CSRs, (2) transient combustible controls are implemented for the areas where reduced HRRs are credited (i.e., CSRs) and are implemented through a TCP which requires materials to be removed immediately following completion of the task, (3) the historical increase in combustible loading in the CSRs when a TCP is used is very low, and (4) there have been no compliance issues or violations associated with the use of transient combustibles in the CSRs.

On October 27, 2020, the NRC staff requested information about the treatment of sensitive electronics and whether the treatment was consistent with the guidance in Frequently Asked Questions (FAQ) 13-0004, "Clarifications on Treatment of Sensitive Electronics," dated December 3, 2013 (Reference 23), including the caveats about configurations that can invalidate the approach (i.e., sensitive electronics mounted on the surface of cabinets and the presence of louver or vents).

In its letter dated November 24, 2020, the licensee explained that its treatment of sensitive electronics is consistent with the guidance in FAQ 13-0004 in which the damage threshold for thermoset cable is used for sensitive electronics within an electrical cabinet. However, the response also explains that the caveats cited in FAQ 13-0004 about configurations that invalidate the approach were not explicitly addressed. The licensee stated that consideration of such configurations should have "negligible impact on fire risk due to the functions associated with sensitive electronics (e.g., a single logic channel)."

The licensee also stated that a "gap" in the analysis could exist where the exposed sensitive electronics are beyond the zone of influence (ZOI) of the ignition source determined by thermoset failure criteria allowed by FAQ 13-0004 but within a ZOI defined by the nominal damage criteria for sensitive electronics (i.e., criteria from NUREG/CR-6850). The licensee suggested that its treatment of the potential for fire to grow beyond the analyzed ZOI offset the this identified "gap." As further justification of its treatment, the licensee provided an evaluation of a sampling of seven sensitive electronics cabinet configurations and determined that the sensitive electronics: (1) have no impact on a PRA credited function, (2) are not damaged in fire, or (3) failure is already accounted for in the fire PRA scenarios.

On February 26, 2021 (Reference 24), the NRC staff stated its view that the limited sampling was insufficient to determine the impact of the modeling assumption on the RICT calculations and with this observation and others discussed above, and the staff therefore requested justification that the licensee's treatment of sensitive electronics will have negligible impact on the RICT calculations.

In its March 23, 2021, response, the licensee described its evaluation of a sampling of cabinet configurations. The licensee explained that a plant walkdown was conducted by the Site Risk Management Engineer and a Senior Reactor Operator to identify sensitive electronics in risk significant areas of the CPS. For each of these areas, the licensee explained that either sensitive electronics were not associated with fire PRA credited equipment or failures of the sensitive electronics are already accounted for by the failures of other targets in the target set (e.g., fire-induced failure of different components that support the same function). The licensee also stated that these insights are representative of sensitive electronics in other areas of the plant not explicitly evaluated as part of the walkdown and that this supports the conclusion that cabinet configurations that invalidate the use of FAQ 13-004 would have negligible impact on fire risk.

Based on its review of the information provided by the licensee, the NRC staff concludes that the licensee's approach of using the thermal damage threshold from FAQ 13-0004 for sensitive electronics without explicit consideration of the caveats about cabinet configuration that invalidate the approach is acceptable for the application. It is found acceptable because the licensee showed that sensitive electronics existing in the plant either are not associated with fire PRA credited equipment or their failures are already accounted for by the failures of other targets in the target set in propagating and non-propagating fire scenarios.

On October 27, 2020, the NRC staff requested information about whether minimum joint human error probabilities (HEP) values less than 1E-05 were assumed in the fire PRA. NUREG-1921, "EPRI/NRC-RES Fire Human Reliability Analysis Guidelines- Final Report," July 2012 (Reference 25), discusses the need to consider a minimum value for the joint probability of HFEs. NUREG-1921 refers to Table 2-1 of NUREG-1792, "Good Practices for Implementing Human Reliability Analysis (HRA)," April 2005 (Reference 26), which recommends that joint HEP values should not be below 1E-5. Table 4-4 of Electrical Power Research Institute (EPRI) 1021081, "Establishing Minimum Acceptable Values for Probabilities of Human Failure Events,"[2] provides a lower limiting value of 1E-6 for sequences with a very low level of dependence. Therefore, the guidance in NUREG-1921 allows for assigning joint HEPs that are less than 1E-5, but only through assigning proper levels of dependency. The NRC staff also requested the results of a sensitivity study if a minimum joint HEP less than 1E-05 is used in the fire PRA.

[2] Available from Electric Power Research Institute, 3420 Hillview Avenue, Palo Alto, California 94304.

In its response dated November 24, 2020, the licensee explained that for fire PRA dependency analysis a minimum joint HEP of 1E-06 was used unless the timeframe for completing one or more actions in the combination was longer than 15 hours. In these cases, a lower minimum joint HEP of 5E-07 was used.

The licensee also explained that a sensitivity study was performed in which a minimum joint HEP of 1E-05 was applied in the sensitivity case and calculated the RICTs for a sample of eight LCOs selected because they represent plant configurations for which the RICTs are most likely to change in the sensitivity case. The results of the sensitivity study show that the calculated RICTs essentially did not change as the decreases in all calculated RICTs are less than 1 percent. The NRC staff finds the licensee's application of minimum joint HEP values acceptable because the licensee shows it meets the intent of the above guidance to establish an appropriate minimum joint HEP value, with allowance for further decrease consistent with the level of dependency of HEPs in the combination; and even though the minimum joint HEP value for the fire PRA is set at 1E-06 opposed to 1E-05, the licensee's sensitivity study demonstrated that setting the minimum joint HEP for the fire PRA to 1E-05 rather than 1E-6 has a minimal impact on the RICT application.

On October 27, 2020, NRC staff requested information about how well sealed cabinets were treated in the fire PRA. Information was requested about how fire propagation outside of well-sealed motor control centers (MCC) cabinets greater than 440 V was evaluated and whether it was consistent with the NRC guidance in fire PRA FAQ 14-0009, "Treatment of Well-Sealed MCC Electrical Panels Greater than 440V," dated April 29, 2015 (Reference 27). Information was also requested about whether well-sealed cabinets less than 440 V are included in the Bin 15 count of ignition sources consistent with guidance in NUREG/CR-6850.

In its November 24, 2020, response, the licensee explained that all MCCs are assumed not to be well-sealed and, therefore, all fires originating from MCC cabinets are assumed to damage external targets. Accordingly, the refinements using the guidance in FAQ 14-0009 were not applied. The licensee also explained all other cabinets are also assumed not to be well-sealed, and therefore, cabinets less than 440 V are included in the Bin 15 count and fires postulated for those cabinets are evaluated for the potential to damage external targets. The NRC staff finds the licensee's treatment of well-sealed cabinets consistent with the above guidance.

Based on its review, the NRC staff finds that the licensee's fire PRA has been adequately peer reviewed against the current versions of the PRA standard and RG 1.200, that the licensee has adequately closed the F&Os, and the licensee has performed the fire PRA using the most current NRC approved guidance. Therefore, the NRC staff concludes that the fire PRA is technically acceptable to support the RICT program.

3.2.4.1.3 Evaluation of External Hazards

The NRC staff's SE for NEI 06-09 states that sources of risk besides internal events and internal fires (i.e., seismic and other external events) must be quantitatively assessed if they contribute significantly to configuration-specific risk. The SE further states that bounding analyses or other conservative quantitative evaluations are permitted where realistic PRA models are unavailable. In addition, the SE concludes that if sources of risk can be shown to be insignificant contributors to configuration risk, then they may be excluded from the RMTS.

As discussed in Section 3.2.4 of this SE, the PRA models used for the RICT program include contributions from internal events, including internal flooding, and fire events. In addition, the

licensee provided a conservative estimate of the seismic CDF (SCDF) and seismic LERF (SLERF) 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. The licensee addressed the risk from seismic events and other external hazards in the context of this application in Enclosure 4 to the LAR.

In the LAR Enclosure 4, Section 2, the licensee stated that for the overall process, consistent with NUREG-1855, Revision 1, external hazards may be addressed by: (1) screening the hazard on low frequency of occurrence, (2) bounding the potential impact and including it in the decisionmaking, and (3) developing a PRA model to be used in the RMAT/RICT calculation. The licensee stated that as part of this process the following two aspects of the external hazard contribution to risk should be considered.

- The first is the contribution from the occurrence of beyond design basis conditions, e.g., winds greater than design, seismic events greater than design-basis earthquake, etc. These beyond design basis conditions challenge the capability of the SSCs to maintain functionality and support safe shutdown of the plant.

- The second aspect addressed are the challenges caused by external conditions that are within the design basis, but still require some plant response to assure safe shutdown, e.g., high winds or seismic events causing loss of offsite power, etc. While the plant design basis assures that the safety-related equipment necessary to respond to these challenges are protected, the occurrence of these conditions nevertheless causes a demand on these systems that presents a risk.

The NRC staff reviewed Enclosure 4 to the LAR dated April 30, 2020, and supplemental information dated November 24, 2020, to determine the acceptability of the consideration of risk from seismic events and other external hazards for this application.

Seismic Hazard Contribution to the RICT

In LAR Enclosure 4, the licensee provided a conservative estimate for the risk from seismic events for use in determining the configuration risk for the RICTs identified in the LAR. The licensee explained in the LAR Enclosure 4, Section 3.0, that RICT calculations will include a risk contribution from seismic events using a “seismic penalty” approach. A seismic penalty, commonly used in RICT calculations and for estimation of SCDF, is performed using a mathematical convolution of the seismic hazard and plant level seismic capacity curves. For SLERF, the penalty is obtained by multiplying the calculated SCDF by an average seismic conditional large early release probability (CLERP). The licensee’s approach for including the seismic risk contribution in the RICT calculation is to add a constant SCDF and SLERF to each RICT calculation. Section 3.3.5 of NEI 06-09 states that for stations without external events PRAs, the station should apply one of three acceptable methods to determine external event risk. The second method, used for CPS, is to perform a reasonable bounding analysis which must be case-specific, technically verifiable, and must be shown to be conservative from the perspective of RICT determination. For application to CPS RICT calculations, the licensee proposed to add a SCDF contribution of 6.4E-06 per year and a SLERF contribution of 1.6E-06 per year to the configuration-specific delta risk contribution from internal events (including internal flooding) and internal fire events.

The licensee’s proposed SCDF estimate is based on using the plant-specific seismic hazard curves developed in response to the Near-Term Task Force Recommendation 2.1 dated March

31, 2014 (Reference 28), and supplemented on August 21, 2014 (Reference 29), and a plant-level high confidence of low probability of failure (HCLPF) capacity of 0.30g (gravity) referenced to peak ground acceleration (PGA). HCLPF is the capacity representing 95 percent confidence that the conditional probability of failure of an SSC is 5 percent or less. The uncertainty parameter for seismic capacity was represented by a combined beta factor of 0.4. The HCLPF parameters used for the CPS SCDF estimate are those cited for the CPS in Table B-2 and C-2 of Results of Safety/Risk Assessment of Generic Issue 199, 'Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants,'" dated September 2, 2010 (Reference 30). Approximate SCDF estimates were developed in Reference 30 using a method which includes integrating the mean seismic hazard curve and the mean plant-level fragility curve for each NPP. This method, developed by Kennedy (1997), is discussed in Section 10.8.9 of AMSE/ANS RA-Sa-2009 and has previously been used by the staff in the resolution of GI-194, "Implications of Updated Probabilistic Seismic Hazard Estimates," and during reviews of various risk-informed license amendments. The 0.30g PGA value is consistent with the CPS individual plant examination of external events (IPEEEs) review level earthquake. The licensee's estimation of the SCDF is performed by convolving the PGA based seismic hazard curve for the CPS site using the geometric mean of the 19 seismic hazard intervals (from 0.0005g to 10g) with the CPS PGA based HCLPF as shown in LAR Enclosure 4, Table E4-2. The NRC staff review finds that the method used to estimate the SCDF is acceptable because it is consistent with the approach used in Reference 30.

As described by the licensee in LAR Enclosure 4, Section 3, the proposed SLERF penalty of 1.6E-06 per year was determined by estimating the average seismic conditional large early release probability (CLERP) at 0.25 and multiplying it by the estimated SCDF of 6.4E-06 per year. The licensee explained that an estimate of the average seismic CLERP was determined using: (1) the average contribution of different accident types to SLERF using fragility information from completed seismic PRAs and generic guidance, and (2) the CLERP for the current CPS internal events PRA model of record for each accident type. The average percent contribution of different accident types to seismic LERF was then multiplied by the internal events PRA CLERP to produce a seismic CLERP for the designated accident types which were in turn used to calculate a sequence-weighted average seismic CLERP. The LAR indicates that the seismic PRA does not produce different accident scenarios from the internal events PRA but rather a different distribution of accident scenario types for seismic events. The LAR further explains that containment isolation failures were evaluated to ensure that random or seismically induced failures leading directly to LERF are insignificant risk contributors. The LAR presents a graphical approach for determining the average contribution of different accident types to SLERF based on fragility information from several cited sources. The graphic resembles an event tree in which the top events and end states are used to define the accident types of interest and the branch point probabilities are used to calculate the percent contribution of each accident type to the total SCDF. The branch point probabilities are determined by the seismic failure of components relevant to the branch points based on "review of industry fragility information."

In its supplement dated November 24, 2020, the licensee provided an additional description of how the branch point probabilities in LAR Enclosure 4, Figure E4-1, were determined. The licensee explained that nodal probabilities for the seismic capacities assigned to each node (i.e., branch point) of the graphic are calculated using a typical double lognormal fragility probability model. The types of SSCs typical to a given node are discussed in the LAR (e.g., containment structure, RPV supports, DG or control building failures, off-site power, and containment isolation valves). The licensee explained that the seismic capacity was selected from the lower

end of the ranges for over 150 representative capacities compiled from a review of industry studies that include the EPRI 3002000709 report, “Seismic Probabilistic Risk Assessment Implementation Guide,” December 2013 (Reference 31), Lawrence Livermore National Laboratory report UCID-20571, "Compilation of Fragility Information from Available Probabilistic Risk Assessments,"[3] and several plant-specific seismic PRAs performed in response to the NRC staff’s 10 CFR 50.54(f) request for information dated March 12, 2012 (ADAMS Accession No. ML12053A340), with regard to Near Term Task Force Recommendation 2.1. The licensee explained that the SCDF fraction for each scenario type was determined by convolving the PGA based seismic hazard curve for the CPS site using the geometric mean of 10 seismic hazard intervals from 0.05g to 3g (which is a more coarse convolution than the convolution used to calculate the total seismic CDF but detailed enough for this use). Based on this convolution, the nominal fraction of seismic CDF for each scenario type was calculated to determine the seismic CLERP as discussed above.

In its supplement dated November 24, 2020, the licensee provided justification that the SLERF “penalty” for CPS is conservative. The licensee stated that its approach to estimate the SLERF is based on the combination of: (1) an estimated SCDF which is not necessarily conservative, (2) an average seismic CLERP which is estimated conservatively, and (3) use of a SLERF “penalty” in the RICT calculations which is conservative because the entire CDF and LERF is applied in every RICT calculation. The licensee discussed several conservatisms made in estimating the average seismic CLERP such as: (1) the seismic-induced loss of offsite power is assumed to occur at a probability of 1.0 for the entire seismic hazard curve, and (2) the low end of the capacity distributions compiled from generic sources was used to determine the node probabilities to estimate the nominal fraction of SCDF for each scenario type. The licensee also presented the results of a sensitivity study on the impact of the seismic penalty factor on the calculated RICTs by increasing the seismic penalty in the sensitivity case by a factor of two. The results show that the seismic penalty factor has a very small impact on the RICT calculated for risk significant configurations (i.e., short RICTs).

The NRC staff finds the licensee’s development of its seismic CLERP acceptable because it used several conservative assumptions as discussed above and was derived using a combination of industry seismic PRA results and plant-specific information. Additionally, a seismic CLERP of 0.25 is within the range of seismic CLERP values observed by the staff for plants with current seismic PRAs. The NRC staff finds the licensee’s estimate of and use of its SLERF penalty acceptable for this application because: (1) reasonable or somewhat conservative assumptions are used in its estimation and application of this penalty in the RICT program and (2) the seismic penalty has a minor impact on the calculated RICTs.

The NRC staff finds that for RICTs associated with SSCs credited in the design basis to mitigate seismic events, the licensee's proposed methodology captures the risk associated with seismically induced failures of redundant SSCs because such SSCs are assumed to be fully correlated. By assuming full correlation, the seismic risk for those RICTs will not increase if one of the redundant SSCs is unavailable because simultaneous failure of all redundant trains would be assumed in a seismic PRA. During RICTs for SSCs not credited in the design-basis seismic event, but which could be used when credited SSCs fail, the proposed methodology for considering seismic risk contributions may be non-conservative because the seismically-induced failure of such SSCs during the RICT may not be included in the risk increase. However, the occurrence and degree of non-conservatism depends on the plant high confidence in low probability of failure (HCLPF) value used for the RICT calculations, as

[3] Available at https://www.osti.gov/servlets/purl/5455630.

compared to the HCLPF values for such SSCs. The degree of non-conservatism will be low or nonexistent if the plant HCLPF value is lower than most or all SSCs impacted by a seismic event. During RICTs for SSCs that are not used to mitigate a seismic event, the proposed methodology for considering seismic risk contributions is conservative because the seismically induced failure of such SSCs would not result in a risk increase associated with the plant configuration during the RICT, but the seismic penalty is still included in the calculation.

The licensee also calculated the total (i.e., across the entire hazard curve) seismically induced LOOP frequency of 1.7E-03 per year for CPS, which is about 6 percent of the total unrecovered LOOP frequency addressed in the IEPRA for the CPS. Additionally, the license calculated that the below design basis seismic-induced LOOP frequency is about 4 percent of the total unrecovered LOOP frequency already addressed in the internal events PRA for the CPS. The NRC staff evaluated the analysis and finds that the analysis adequately addresses the impact of seismically induced LOOP and finds it has an insignificant impact on the RICT program calculations.

In summary, the NRC staff finds the licensee's proposal to use the SCDF contributions of 6.4E-06 per year, and a SLERF contribution of 1.6E-06 per year acceptable for the licensee's RICT program for CPS because: (1) the licensee used the most current site-specific seismic hazard information, (2) the licensee used an acceptably low plant HCLPF value of 0.3g consistent with the information for the CPS in the GI-199 evaluation, (3) reasonable industry seismic PRA results and plant-specific information informed the calculation of the seismic CLERP, and (4) adding the seismic risk contribution to RICT calculations, which assumes the 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, as discussed above.

Extreme Winds and Tornado Hazards

LAR Enclosure 4, Section 4, discusses the licensee's evaluation of the risk from the extreme winds and tornadoes hazards. Evaluation of the extreme winds and tornado hazard has been updated since the licensee's IPEEE. The basis for the insignificant impact of extreme winds and tornados (including tornado-generated missiles) for this application relies on the design of SSCs and tornado missile analysis. Table E4-7 of the same enclosure presents the licensee's screening criteria used to disposition the risk for the extreme wind and tornado hazards. Table E4-7 indicates that criterion "PS2" (Design-basis hazard cannot cause a core damage accident) and "PS4" (Bounding mean CDF is < 1E- 6/y (year)) were used to screen the extreme wind and tornado hazard.

In the LAR, the licensee stated that wind damage is bounded by tornadoes and that the tornado wind speed that would be exceeded at a frequency of 1E-07 per year is less than the CPS design wind speed value according to NUREG/CR-4461, Revision 2, "Tornado Climatology of the Contiguous United States," February 2007 (Reference 32), using the enhanced Fujita Scale. The licensee stated that subsequent to its IPEEE screening evaluation of extreme winds it has performed a number of tornado missile protection (TMP) evaluations of CPS. The licensee stated that in 2007 an updated CPS TORMIS-based tornado missile risk analysis was performed. The 2007 TORMIS quantification results exceeded the 1E-06 per year CDF acceptance criterion. However, the evaluation identified the five largest contributors to tornado missile CDF, which, if removed, would reduce the tornado-missile CDF to 6.5E-07 per year. The licensee stated that subsequent to the study, three of the associated targets were modified by installing missile shielding and two of the associated targets were re-assessed and it was

shown that the existing concrete enclosure and backfill provide adequate protection. Another tornado missile evaluation was performed in 2015-2016 in response to Regulatory Issue Summary 2015-06, "Tornado Missile Protection," dated June 20, 2015 (Reference 33), and NRC Enforcement Guidance Memorandum 15-002, "Enforcement Discretion for Tornado-Generated Missile Protection Noncompliance," dated June 10, 2015 (Reference 34). The licensee stated that the 2015-2016 tornado-missile evaluation did not alter the results of the conservatively performed 2007 tornado-missile evaluation study.

The licensee additionally stated that the high winds and tornado screening was performed considering SSCs out of service for maintenance and that there was no significant high winds risk impact from allowed maintenance configurations.

Based on the above, the NRC staff finds that the extreme winds and tornado hazard has an insignificant contribution to configuration risk and can be excluded from the calculation of the proposed RICTs.

External Flooding

In the LAR Enclosure 4, Section 5, the licensee provided an evaluation of the risk from the external flooding hazard. The evaluation of external flooding hazards has been significantly updated since the licensee's IPEEE. The licensee's conclusion that the impact of external flooding on this application is insignificant is based on the results documented in the licensee's flood hazard reevaluation report (FHRR) for CPS dated March 12, 2014 (Reference 35). Table E4-7 of the LAR Enclosure 4 presents the licensee's screening criteria used to disposition the risk for the external flooding hazard. Table E4-7 also indicates that criterion "C1" (event damage potential is less than events for which plant is designed) was used to screen the external flood hazard. The NRC staff evaluation issued November 18, 2015 (Reference 36), concludes that the reevaluted flood hazard mechanisms at Clinton are bounded by the current design-basis.

In LAR Enclosure 4, Section 5, the licensee stated that the results of the FHRR show that flooding from all mechanisms except local intense precipitation (LIP) are bounded by the current LB and the plant response is considered adequate. In its CPS Mitigating Strategies Assessment dated March 24, 2016 (Reference 37), the licensee identified that the model used to develop the LIP flood-causing mechanism was found to incorrectly simulate rain-on-buildings. The licensee's revised calculation identifies the radwaste building as subject to 1.2 inches of standing water. The licensees March 24, 2016, letter concluded that no safe shutdown SSCs are located in the radwaste building. Therefore, the water leakage into the radwaste building would not impact CPS safety functions. The licensee additionally stated that there are no configuration specific considerations related to the hazard screening discussed above.

Based on the above, the NRC staff finds that the external flooding hazard has an insignificant contribution to configuration risk and can be excluded from the calculation of the proposed RICTs.

Other External Hazards

The licensee provided its assessment of the external hazard risk for the RICT program in LAR Enclosure 4, "Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models." In Enclosure 4, the licensee stated that this assessment is based on an update of the CPS IPEEE external hazard screening evaluation. The licensee listed the

hazards assessed in LAR Enclosure 4, Table E4-7. The NRC staff notes that this list is essentially the same list of hazards as presented in Table 4-1 of NUREG-1855, Revision 1. The NRC staff finds that the list of external hazards considered by the licensee is consistent with the hazards listed in Appendix 6-A of the ASME/ANS RA-Sa-2009 PRA Standard, which is endorsed in RG 1.200, Revision 2. NRC staff also notes that the Initial Preliminary Screening criteria and Progressive Screening criteria used and presented in LAR Table E4-8 are the same criteria presented in Supporting Requirements EXT-B1 and EXT-C1 of the ASME/ANS PRA Standard for screening external hazards, as endorsed by RG 1.200, Revision 2.

In LAR Table E4-7 and the supplement to the LAR dated November 24, 2020, the licensee provided a screening disposition for each non-seismic external hazard as well as other hazards and concluded that no unique PRA model for these hazards is required in order to assess configuration risk for the RICT program.

The licensee explained for the snow hazard that the CPS USAR addresses design snow and ice loads using “the latest hazard information.” The licensee also identified that snow or ice loading is screened using criteria in LAR Enclosure 4, Table E4-8; criterion “C1” (event damage potential is less than events for which the plant is designed), and because it is a slow developing event, criterion “C5” (event develops slowly, allowing adequate time to eliminate or mitigate the threat). The licensee explained that RMAs such as those described in the station’s adverse weather procedures will ensure that the assumptions that resulted in screening the hazard will continue to be valid during the proposed RICTs. The licensee explained for the sand or dust storm hazard that CPS is not located in an area that is impacted by sand or dust storms. The licensee also identified that in addition to criterion “C1” that criterion “C3” also applies to this hazard (event cannot occur close enough to the plant to affect it). The licensee explained for the ice cover hazard that the CPS USAR stipulates that the submerged location of the ultimate heat sink (UHS) pond suction prevents ice formation or ice jams from affecting the performance of the UHS. The licensee also explained that scheduled periodic reviews, as discussed in NEI 00-04, will be conducted to evaluate new insights from available information. If it is determined that there are changes that can impact categorization, the risk information and the categorization process will be updated. NRC staff finds that the bases for screening the snow, sand or dust storm, and ice cover hazards are acceptable because they consider the as-built, as-operated plant, use current hazard information, and will be updated if changes that can impact categorization are identified from periodic reviews.

The NRC staff’s review of the information in the submittal as supplemented finds that the contributions from the 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.

External Hazards Conclusion

The NRC staff concludes that the licensee's approach for considering the impact of seismic events, non-seismic external hazards and other hazards for the CPS in the RICT calculations is acceptable because the licensee included a technically acceptable quantitative assessment of the seismic risk for the CPS and configuration specific tornado missile risk for the CPS consistent with the guidance in the NEI 06-09 and demonstrated the insignificant contribution to configuration risk from other external hazards on the proposed RICTs.

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 indicates that periodic assessment should 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 3, for small increases in risk.

NEI 06-09-A further stipulates that configuration risk should be assessed to determine the RICT and establishes the criteria for incremental core damage probability (ICDP) and incremental large early release frequency (ILERP) on which to base the RICT. An ICDP of 1E-5 and an ILERP of 1E-6 are used as the risk measures for calculating individual RICTs. These limits are consistent with NUMARC 93-01, Revision 4F "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," dated April 27, 2018 (Reference 38).

NEI 06-09-A as modified by the limitations and conditions in the associated SE requires that the cumulative impact of implementation of an RMTS be periodically assessed and shown to result in: (1) a total risk impact below 1E-5/reactor-year for changes to CDF, (2) a total risk impact below 1E-6/year for changes to LERF, and (3) the total CDF and total LERF must be reasonably shown to be less than 1E-4/reactor-year and 1E-5/reactor-year, respectively. The licensee indicated in Enclosure 5 of the submittal that the estimated total CDF and LERF meet the 1E-4/reactor-year CDF and 1E-5/reactor-year LERF criteria of RG 1.174 consistent with the guidance in NEI 06-09-A and that these guidelines will be satisfied for implementation of a RICT.

On October 27, 2020, the NRC staff requested a summary of how the SOKC investigation was performed in the baseline PRAs supporting the TSTF-505 application and how it will be addressed in risk metrics used in the RICT application. In its response dated November 24, 2020, the licensee showed that the combined impact on internal and fire events is a 1.5 percent increase in CDF and 0.6 percent increase in LERF and that there is adequate margin between the total mean CDF and LERF values (i.e., 8.86E-05 and 7.11E-06, respectively) and RG 1.174 guidelines to accommodate further increase before the total threshold vales are reached. These updated values demonstrate that the estimated total CDF and LERF meet the 1E-4/reactor-year CDF and 1E-5/reactor-year LERF criteria of RG 1.174, consistent with the guidance in NEI 06-09-A.

The licensee has incorporated NEI 06-09-A in the RICT program of TS 5.5.17 and, therefore, it can calculate the RICT appropriately to assess and ensure that any risk increases are small and in accordance with RG 1.174, Revision 3, and the intent of RG 1.177, Revision 1. Also, the estimate of the current total CDF and LERF meets the intent of the RG 1.174, Revision 3, acceptance guidelines. Therefore, the NRC staff finds that the licensee's RICT program is consistent with NEI 06-09-A guidance and is acceptable.

3.2.4.1.5 Key Assumptions and Uncertainty Analyses

Using PRAs to evaluate TS changes requires consideration of the assumptions made within the PRA that can have a significant influence on the ultimate acceptability of the proposed changes. The licensee considered PRA modeling uncertainties and their potential impact on the RICT program and identified, as necessary, applicable RMAs to limit the impact of these uncertainties. In Enclosure 9 of the LAR, the licensee discussed key assumptions and key sources of uncertainty along with providing the dispositions for impact on the risk-informed

application or applicable sensitivities. The licensee's evaluation the CPS PRA model to identify the key assumptions and key sources of uncertainty for this application consistent with RG 1.200 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.

In regard to the fire PRA, the licensee stated in LAR Enclosure 9, Section 4, that it used guidance from NUREG-1855, Revision 1, and guidance for fire PRA development including NUREG/CR-6850, "EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities," to address the fire PRA uncertainty analysis. The licensee explained that plant-specific assumptions and sources of modeling uncertainty identified from the fire PRA were considered, as well generic industry sources of uncertainty from EPRI TR 1026511. The licensee explained that the fire PRA uncertainties were organized by the fire PRA topics presented in NUREG/CR-6850.

The licensee explained that it has used consensus modeling approaches from NUREG/CR-6850 and guidance from NUREG-7150[4] and fire PRA FAQs. In LAR Enclosure 9, Table E9-3, the licensee dispositioned the fire PRA modeling uncertainties stating in each case that they do not present a significant impact on the RICT calculations and no RMAs (or additional RMAs) were required to address the uncertainty.

The NRC staff reviewed the licensee's dispositions for the RICT application provided in LAR Enclosure 9, Tables E9-1, E9-2, and E9-3, to understand key assumptions and sources of modeling uncertainty and noted sources of uncertainty that did not appear to fully dispositioned and appeared to have the potential to impact the RICT calculations. In the LAR, the licensee stated that certain components were conservatively assumed to be failed because of the lack of cable data in certain locations, and because of this it performed two sensitivity studies to determine the impact. These components were referred to as unknown location (UNL) components. The licensee stated that based on the sensitivity results, it concluded that its approach does not "introduce any epistemic uncertainties" that would impact the RICT calculations. However, the licensee did not provide the results of the uncertainty analysis in the LAR. On October 27, 2020,, the NRC staff requested identification of the systems or components that were assumed to fail because of the lack of cable routing and requested the licensee to provide justification that this treatment has an inconsequential impact on the RICT program.

In its response dated November 24, 2020, the licensee identified the UNL components and stated that "[m]ost of the UNL components are associated with systems that are not within the scope of the TSTF-505 RICT program and do not serve support function for the TSTF-505 RICT LCOs." The licensee also explained that it performed a sensitivity study of the impact of this treatment on calculated RICTs for a sampling of TS LCOs selected for this study because their estimated RICTs are less than 30 days. In the sensitivity case, the RICT calculation was based on fire PRA modeling in which all UNL failures were removed. The NRC staff notes that this removal of the UNL component failures has the effect of eliminating the possible impact of the conservatism associated with modeling the UNL components. Therefore, the NRC staff concludes that the UNL components will not pose a significant impact to the RICT program.

On October 27, 2020, the NRC staff requested that the licensee justify that the uncertainty associated with post-fire HRA modelling has an inconsequential impact on calculated RICTs for

[4] Available at https://www.nrc.gov/reading-rm/doc-collections/nuregs/contract/cr7150/

components supporting TS LCO conditions in the RICT program. In its November 24, 2020, letter, the licensee responded that it evaluated FPRA HRA uncertainty as a part of its parametric uncertainty evaluation. Furthermore, the licensee presented the results of a sensitivity study for a set of TS LCOs to determine the impact of using point-values rather than parametric mean values on the calculated RICT values based on CDF. Based on the above, the NRC staff finds the licensee's treatment of post-fire HRA modeling is consistent with guidance in NUREG-1855, Revision 1 and is therefore acceptable.

Based on the above, the NRC staff concludes the licensee performed an adequate assessment to identify the potential key sources of uncertainty, and key assumptions consistent with the guidance in NUREG-1855 and associated EPRI TR-1016737 and EPRI TR-1026511. Therefore, the NRC staff finds that the licensee has satisfied the guidance in RG 1.177, Revision 1 (Sections 2.3.4 and 2.3.5), and RG 1.174, Revision 3 (Section 2.2.2), 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.

PRA Scope and Acceptability Conclusions

Based upon its review, the NRC staff finds that the licensee (1) has reviewed the PRA using endorsed guidance and adequately resolved all identified issues, (2) has established a periodic update and review process to update the PRA and associated CRMP model to incorporate changes made to the plant and PRA methods and data consistent with the RICT program, and (3) will calculate RICTs using NRC-accepted PRA methods. Therefore, the NRC staff concludes that the licensee has and will maintain a PRA that is technically adequate to support implementation of the RICT program.

Based on the above, the NRC staff finds that the licensee has satisfied the intent of RG 1.177, Revision 1, and RG 1.174, Revision 3, and that the scope of the PRA model and the use of a bounding analysis for seismic events is appropriate for this application.

3.2.4.1.6 Application of PRA Models in the RICT Program

Table E1-1 in Enclosure 1 to the LAR, as supplemented by the licensee in its letters dated November 24, 2020, and March 23, 2021: (1) identifies each TS LCO condition in scope of the RICT program and, the SSCs covered by the LCO, as applicable, (2) indicates whether the SSC is modeled in the PRA, and (3) for the cases in which the SSCs are not explicitly modeled, explains how the PRA uses surrogate events that bound the function(s) of the TS LCO SCC(s).

The NRC staff noted for some LCOs identified in Table E1-1 of Enclosure 1 to the LAR, the licensee explained that the associated SSCs are not modeled in the PRAs but will be considered using a surrogate event. For certain LCOs, it was not clear to NRC staff whether the surrogate PRA modeling will be adequate to support the RICT calculations. The LAR, in Table E1-1 indicates that the "relief function" is not modeled and, therefore, surrogate modeling will be used. On October 27, 2020, the NRC staff requested clarification of the surrogate modeling that will be used to model TS LCO 3.3.6.5, "Relief and Low-Low Set (LLS) Instrumentation," Condition A (one trip system inoperable). Specifically, NRC staff requested: (1) confirmation of which SSCs for this LCO are not explicitly modeled in the PRAs, (2) explanation of the surrogate modeling that will be used for the SSCs, and (3) justification that the surrogate modelling appropriately represents the failure of the design function associated with TS LCO Condition A. In its response dated November 24, 2020, the licensee clarified that the relief (or

overpressure) function of the SRVs is modeled in the PRAs, but that the pressure instrumentation providing the signal for the SRVs to open on high reactor pressure is not modeled. Therefore, both the relief and low-low set instrumentation (which open SRVs at lower pressure) is not included in the PRA models. The licensee explained that the two LLS SRVs (one on Division 1 and the other on Division 2) will be used as a conservative surrogate for the relief and LLS instrumentation. The NRC finds that the licensee's surrogate modeling of the relief and LLS instrumentation serves as an appropriate substitute and appropriately represents the failure of the design function associated with TS LCO 3.3.6.5 Condition A.

Risk Assessment Approaches and Methods

Changes to the PRA are expected to occur over time to reflect changes in PRA methods and changes to the as-built, as-operated, and maintained plant to reflect the operating experience at the plant as specified in RG 1.200, Revision 2. Changes in PRA methods are addressed by constraint e. of TS Administrative Section 5.5.17:

> 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 used to support this license amendment, 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.

The NRC staff finds that this constraint is acceptable because it adequately implements the RICT program using models, methods, and approaches consistent with applicable guidance that are acceptable to the NRC.

Credit for FLEX

The NRC staff's memorandum dated May 30, 2017, "Assessment of the Nuclear Energy Institute 16-06, 'Crediting Mitigating Strategies in Risk-Informed Decision Making,' Guidance for Risk-Informed Changes to Plants Licensing Basis" (Reference 39), provides the NRC staff's assessment of challenges to incorporating FLEX equipment and strategies into a PRA model in support of risk-informed decisionmaking in accordance with the guidance of RG 1.200, Revision 2. The review of the FLEX strategies and modeling for the PRA was performed as a combined effort with the CPS LAR for adoption of 10 CFR 50.69, which the NRC staff approved previously. The basis for acceptability is documented in the SE for 10 CFR 50.69 and the conclusions apply to this SE as well.

3.2.4.2 Tier 2: Avoidance of Risk-Significant Plant Configurations

As prescribed in RG 1.177, Revision 1, the second tier provides that a licensee should provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific plant equipment is taken out-of-service in accordance with the proposed TS change.

NEI 06-09-A does not permit voluntary entry into high-risk configurations, which would exceed instantaneous CDF and LERF limits of 1E-3/year and 1E-4/year, respectively. The guidance in NEI 06-09-A specifies that if the instantaneous CDF and LERF limits are exceeded for emergent

conditions, then implementation of RMAs is required. It further requires implementation of RMAs when the actual or anticipated risk accumulation during a RICT will exceed one-tenth of the ICDP or ILERP limit (the RMAT). Such RMAs may include rescheduling planned activities to lower risk periods or implementing risk-reduction measures. The limits established for entry into a RICT and for RMA implementation are consistent with the guidance of NUMARC 93-01, Revision 4F, endorsed by RG 1.160, Revision 4[5], 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, Enclosure 12 of the LAR identifies three kinds of RMAs:

- 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).

The LAR also explains that RMAs will be implemented, in accordance with current plant procedures, no later than the time at which the ICDP or ILERP is reached and under emergent conditions when the instantaneous CDF and LERF thresholds are exceeded.

Based on the licensee's incorporation of NEI 06-09-A in the TS as discussed in LAR Attachment 1 and use of RMAs as discussed in LAR Enclosure 12, "Risk Management Actions" and the licensee supplements, and because the proposed changes are consistent with the guidance of RG 1.174, Revision 3, and RG 1.177, Revision 1, the NRC staff finds that 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 third tier provides 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.

NEI 06-09-A specifies that the RMTS risk assessment process should be integrated into station-wide work control processes and defines the necessary attributes of the RMTS program structure. In the conduct of RMTS, procedural guidance is required for conducting and using the results of the risk assessment. In Enclosure 8 of the LAR, "Attributes of the Real-Time Risk Model," the licensee confirms that future changes made to the baseline PRA model, changes made to the baseline PRA model for translation to the online model, and changes made to the online model configuration files are controlled and documented by plant procedures.

Based on the licensee's incorporation of NEI 06-09-A, in the TS, as discussed in LAR Attachment 1 and the use of RMAs as discussed in LAR Enclosure 12, "Risk Management Actions," as supplemented, and because the proposed changes are consistent with the Tier 3 guidance of RG 1.177, Revision 1, the NRC staff finds that the proposed changes are acceptable.

[5] Available at https://www.nrc.gov/docs/ML1822/ML18220B281.pdf

3.2.4.4 Key Principle 4: Conclusions

Based upon its review, the NRC staff concludes that the licensee has demonstrated the technical acceptability and scope of its PRA models that can support implementation of the RICT program for determining CTs. The licensee has properly considered key assumptions and sources of uncertainty. The licensee's risk metrics are consistent with the approved methodology of NEI 06-09-A and the acceptance guidance in RG 1.177 and RG 1.174. The RICT program is controlled administratively through plant procedures and training. The RICT program follows the NRC-approved methodology in NEI 06-09-A. The NRC staff concludes that the RICT program satisfies the fourth key safety principle of RG 1.177 and is, therefore, acceptable.

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

RG 1.177, Revision 1, and RG 1.174, Revision 3, establish 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 reliability and availability of SSCs impacted by the change. Revision 3 of RG 1.174 states 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. According to LAR Enclosure 11, the SSCs in the scope of the RICT program are also in the scope of the Maintenance Rule. In its letter dated November 24, 2020, the licensee described the approach and methods used for SSC performance monitoring as described in Regulatory Position C.3.2 referenced in RG 1.177 for meeting the fifth key safety principle. Furthermore, in Enclosure 11 of the LAR, the licensee confirmed that the cumulative risk is calculated at least every refueling cycle, but the recalculation period does not exceed 24 months, which is consistent with NEI 06-09-A. This evaluation assures that RMTS program implementation meets RG 1.174 guidance for small risk increases.

The NRC staff concludes that the RICT program satisfies the fifth key safety principle of RG 1.177, Revision 1, and RG 1.174 b, by, in part, monitoring the average annual cumulative risk increase as described in NEI 06-09 and using this average annual increase to ensure the program as implemented meets RG 1.174 guidance for small risk increases therefore, is acceptable. Additionally, the NRC staff concludes that the RICT program satisfies the fifth key safety principle of RG 1.177, Revision 1, and RG 1.174, because, in part, all the affected SSCs are within the Maintenance Rule program which can be used to monitor changes to the reliability and availability of these SSCs.

3.3 <u>Variations from TSTF-505</u>

The NRC staff evaluated the proposed use of RICTs in the variations stated above in Section 2.2.4 of this SE in conjunction with evaluating the proposed use of RICTs in each of the individual LCO, Required Actions, and CTs stated above in Section 2.2.3. The NRC staff's evaluation of the licensee's proposed use of RICTs in the variations against the key safety principles is discussed above in Sections 3.2.1 through 3.2.5. Based on the above Sections 3.2.1 through 3.2.5, the NRC staff finds that each of the five key principles in RG 1.177, Revision 1, and RG 1.174, Revision 3, have been met. Evaluation of the acceptability of the specific proposed use of RICTs is included below.

3.3.1 Application of the RICT Program to Modified Conditions, Required Actions, and CTs

Section 2.2.4.1 of this SE discusses changes proposed in the LAR that modify CTs to permit the application of a RICT.

- LCO 3.6.1.2, states, "Each primary containment air lock shall be OPERABLE." Condition 3.6.1.C, "One or more containment air locks inoperable for reasons other than Condition A or B."
- LCO 3.6.5.2, states, "The drywell air lock shall be OPERABLE." Condition 3.6.5.2.C, "Drywell air lock inoperable for reasons other than Condition A or B."
- Modified CTs in LCOs 3.3.5.1, 3.3.5.3, 3.3.6.1, 3.3.6.3, and 3.3.8.1 are evaluated in Section 3.1.2.3, "Evaluation of Instrumentation and Control Systems."

For Condition 3.6.1.2.C, the potential for containment leakage beyond allowable limits must be assessed to ensure no loss of containment function is associated with the air lock inoperability. The licensee's proposed change to the associated Action C.3 permits consideration of the RICT for restoration of the affected airlock to operable status only when (C.1) action to evaluate overall containment leakage rate per LCO 3.6.1.1 has been immediately initiated using current airlock test results and (C.2) one air lock door is closed. These conditions provide reasonable assurance that any loss of function condition would be detected and preclude usage of the RICT. The licensee proposed the following TS Conditions to add the RICT program modified by a note that states, "Not applicable if leakage exceeds limits or if loss of function." This approach retains the existing requirements and limits the use of a RICT to conditions in which the function can still be performed. The licensee must justify that the required function can still be performed absent an additional failure when a RICT is applied. Therefore, the proposed change to Action 3.6.1.2.C.3 is acceptable.

For Condition 3.6.5.2.C, the potential for containment leakage beyond allowable limits must be assessed to ensure no loss of containment function is associated with the drywell air lock inoperability. The licensee's proposed change to the associated Action C.2 permits consideration of the RICT for restoration of the affected air lock to operable status only when (C.1) a door has been verified closed. These conditions provide reasonable assurance that any loss of function condition would be detected and preclude usage of the RICT. The licensee proposed the following TS Conditions to add the RICT program modified by a note that states, "Not applicable if leakage exceeds limits or if loss of function." This approach retains the existing requirements and limits the use of a RICT to conditions in which the function can still be performed. The licensee must justify that the required function can still be performed absent an additional failure when a RICT is applied. Therefore, the proposed change to Action 3.6.5.2.C.2 is acceptable.

3.3.2 Application of the RICT to Additional ACTIONS Requirements

Section 2.2.4.2 of this SE discusses changes proposed in the LAR that are not Actions listed in TSTF-505. Additional Actions proposed in LCO 3.3.6.4 are evaluated in Section 3.1.2.3. Additional Actions proposed in LCO 3.8.9 are evaluated in Section 3.1.2.2, "Evaluation of Electrical Power Systems."

Condition 3.6.1.6.A applies when one LLS valve is inoperable. Table E1-1 states the design success criterion of Condition 3.6.1.6.A is four of five LLS valves are operable to fulfill the safety

function. In Attachment 4 of the LAR, the licensee identified and provided additional justification for which the LAR proposed applying the RICT program, that varies from TSTF-505, Revision 2:

> Industry guidance developed by the TSTF indicates that this action was excluded because the traveler will not modify Required Actions for systems that do not affect CDF or LERF or for which a RICT cannot be quantitatively determined.
>
> However, CPS proposes to apply a RICT to this action because the function is modeled in the PRA and can be directly included in the RTR tool for the RICT program. As stated in the CPS TS Bases for Required Action A.1, with one LLS valve inoperable, the remaining operable LLS valves are adequate to perform the designed function.

Considering Action 3.6.1.6.A.1 and the associated design success criterion, the NRC staff finds that there is reasonable assurance that the existing requirement allows the use of a RICT for the condition in which the function can still be performed. Based on the above, the NRC staff determines that the proposed change to Action 3.6.1.6.A.1 is acceptable.

3.4 TS Administrative Controls Section

The NRC staff reviewed the licensee's proposed addition of a new program, 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.

TS 5.5.17 requires that the RICT program be implemented in accordance with NEI 06-09-A. This is acceptable because NEI 06-09-A establishes an appropriate framework for an acceptable RICT program.

The TS states that a RICT may not exceed 30 days. The NRC staff determined that 30-day limit is appropriate because it allows sufficient time to restore SSCs to operable status while avoiding excessive out-of-service times for TS SSCs.

The TS states that the RICT may only be used in Modes 1 and 2. This provision ensures that the RICT is only used for determination of CDF and LERF for modes of operation modeled in the PRA.

The TS requires that while in a RICT, any change in plant configuration as defined in NEI 06-09-A must be considered for the effect on the RICT. The TS also specifies time limits for determining the effect on the RICT. These time limitations are consistent with those specified in NEI 06-09-A.

The TS contains requirements for the treatment of CCFs for emergent conditions in which the common cause evaluation is not complete. The requirements are to either: (1) numerically account for the increased probability of CCF or (2) 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. Key Principle 2 of risk-informed decisionmaking is intended to assure that the change is consistent with DID philosophy. The seven considerations supporting the evaluation of the impact of the change on DID are discussed in RG 1.174, including one to preserve adequate defense against potential CCF. 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 CCF and, therefore, support meeting Key Principle 2 as described in RG 1.174. 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 contribute to maintaining DID because the methods limit the exposure time or ensure the availability of alternate SSCs.

The TS contains a provision that risk assessment approaches and methods used 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 RG 1.200, Revision 2. Methods to assess the risk from extending the CTs must be PRA methods used to support this LAR, or other methods approved by the NRC for generic use. As stated in the NRC staff's SE for NEI 06-09-A:

> NEI 06-09, Revision 0, requires an evaluation of the PRA model used to support the RMTS against the requirements of RG 1.200, Revision 1, and ASME RA-S-2002, "Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications," for CC II. This assures that the PRA model is technically adequate for use in the assessment of configuration risk. This capability category of PRA is sufficient to support the evaluation of risk associated with OOS SSCs and establishing risk-informed CTs.

TS 5.5.17 was updated to reflect the current revision of RG 1.200 which incorporates ASME RA-S-2002 by reference.

The NRC staff's SE for NEI 06-09-A also states:

> As part of its review and approval of a licensee's application requesting to implement the RMTS, the NRC staff intends to impose a license condition that will explicitly address the scope of the PRA and non-PRA methods approved by the NRC staff for use in the plant-specific RMTS program. If a licensee wishes to change its methods, and the change is outside the bounds of the license condition, the licensee will need NRC approval, via a license amendment, of the implementation of the new method in its RMTS program. The focus of the NRC staff's review and approval will be on the technical adequacy of the methodology and analyses relied upon for the RMTS application.

The limitation and condition are being relocated from a license condition to the Administrative Controls section of the TS. Proposed TS 5.5.17 restates this limitation and condition from the NRC staff's SE in language that is appropriate for the Administrative Controls section of the CPS TS. This constraint appropriately requires the licensee to utilize the risk assessment approaches and methods previously approved by the NRC and/or incorporated in the RICT program, and requires prior NRC approval for any change in PRA methods to assess risk that are outside those approval boundaries. The NRC staff finds that this requirement is appropriately reflected in the Administrative Controls section of the CPS TS.

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 Administrative Controls section of the TS will assure operation of the facility in a safe manner when the facility uses the RICT program. Therefore, the NRC staff has determined that the requirements of 10 CFR 50.36(c)(5) are satisfied.

4.0 ADDITIONAL CHANGES TO THE OPERATING LICENSE

The licensee did not propose an additional change to the operating license or commit to implementation items in its TSTF-505 LAR.

5.0 SUMMARY

The NRC staff finds that the licensee's proposed implementation of the RICT program for the identified scope of Required Actions is consistent with the guidance of NEI 06-09-A. The licensee's methodology for assessing the risk impact of extended CTs, including the individual CT extension impacts in terms of ICDP and ILERP, and the overall program impact in terms of ΔCDF and ΔLERF, is accomplished using PRA models of sufficient scope and technical adequacy based on consistency with the guidance of RG 1.200, Revision 2. For external hazards, which do not have PRA models, the licensee will use bounding analyses in accordance with NEI 06-09-A guidance and TS Administrative Control. The RICT calculation uses the PRA model as translated into the real-time risk model, and the licensee has an acceptable process in place to ensure the quality of the translation. In addition, the NRC staff finds that the proposed implementation of the RICT Program addresses the RG 1.177 defense-in-depth philosophy and safety margins to ensure that they are adequately maintained and includes adequate administrative controls as well as performance monitoring programs.

Paragraph 50.36(a)(1) of 10 CFR 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.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Illinois State official was notified of the proposed issuance of the amendments on May 12, 2021. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements with respect to installation or use of a facility's components 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 (85 FR 36435, June 16, 2020), 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.

8.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, 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 amendment(s) will not be inimical to the common defense and security or to the health and safety of the public.

9.0 REFERENCES

1. Simpson, P.R., Exelon Generation Company, LLC letter to U.S. Nuclear Regulatory Commission, "Application to Revise Clinton Power Station Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b," dated April 30, 2020 (ADAMS Accession No. ML20121A178).
2. Simpson, P.R., Exelon Generation Company, LLC, letter to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding License Amendment Requests to Adopt TSTF-505, Revision 2, and 10 CFR 50.69," dated November 24, 2020 (ADAMS Accession No. ML20329A433).
3. Simpson, P.R., Exelon Generation Company, LLC, letter to U.S. Nuclear Regualtory Commission, "Response to Request for Additional Information Regarding License Amendment Request to Adopt TSTF-505, Revision 2," dated March 23, 2021 (ADAMS Accession No. ML21082A268).
4. Technical Specifications Task Force letter to U.S. Nuclear Regulatory Commission, "TSTF-505, Revision 2, TSTF Comments on Draft Safety Evaluation for Traveler TSTF-505, Provide Risk-Informed Extended Completion Times and Submittal of TSTF-505, Revision 2," dated July 2, 2018 (ADAMS Package Accession No. ML18183A493).
5. Golder, J.M., U.S. Nuclear Regulatory Commission, letter to Biff Bradley, Nuclear Energy Institute, "Final Safety Evaluation For Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," dated May 17, 2007 (ADAMS Accession No. ML071200238).
6. Nuclear Energy Institute, "Risk-Informed Technical Specifications Initiative 4b: Risk-Managed Technical Specifications (RMTS)," NEI 06-09, Revision 0-A, October 2012 (ADAMS Accession No. ML122860402).
7. U.S. Nuclear Regulatory Commission, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment for Risk-Informed Activities," Regulatory Guide 1.200, Revision 2, March 2009 (ADAMS Accession No. ML090410014).
8. U.S. Nuclear Regulatory Commission, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Regulatory Guide 1.174, Revision 3, January 2018 (ADAMS Accession No. ML 17317A256).
9. U.S. Nuclear Regulatory Commission, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," Regulatory Guide 1.177, Revision 1, May 2011 (ADAMS Accession No. ML100910008).
10. U.S. Nuclear Regulatory Commission, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decisionmaking," NUREG-1855, Revision 1, March 2017 (ADAMS Accession No. ML17062A466).

11 U.S. Nuclear Regulatory Commission, "Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance," NUREG-0800, Chapter 19, Section 19.2, June 2007 (ADAMS Accession No. ML071700658).

12 Gullott, D.M., Exelon Generation Company, LLC, letter to U.S. Nuclear Regulatory Commission, "Clinton Power Station, Updated Safety Analysis Report, Revision 21," dated March 31, 2020 (ADAMS Accession No. ML20217L480).

13 U.S. Nulear Regulatory Commission, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Regulatory Guide 1.200, Revision 1, January 2017 (ADAMS Accession No. ML070240001).

14 American Society of Mechanical Engineers/American Nuclear Society, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications, Addendum A to RA-S-2008," PRA Standard ASME/ANS RA-Sa-2009, June 2005.

15 U.S. Nuclear Regulatory Commission, "U.S. Nuclear Regulatory Commission Acceptance on Nuclear Energy Institute Appendix X Guidance 05-04, 07-12, and 12-13, Close-Out of Facts and Observations (F&Os)," dated May 3, 2017 (ADAMS Accession No. ML17079A427).

16 Simpson, P.R., Exelon Generation Company, LLC, letter to U.S. Nuclear Regulatory Commission, "Application to Adopt 10 CFR 50.69, Risk-informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors," dated April 30, 2020 (ADAMS Accession No. ML20121A241).

17 Wiebe, J. S., U.S. Nuclear Regulatory Commission, letter to David P. Rhoades, Exelon Generation Company, LLC, "Clinton Power Station, Unit No. 1 - Issuance of Amendment No. 237 Regarding Adoption of 10 CFR 50.69, Risk Informed Categorization and Treatment of Structures, Systems and Components of Nuclear Power Reactors (EPID L 2019 LLA 0098)," dated May 19, 2021 (ADAMS Accession No. ML21090A193).

18 Nuclear Energy Institute, "Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines, Draft Version H," NEI 07-12, Revision 0, November 2008 (ADAMS Package Accession No. ML17086A431).

19 Wiebe, J.S., U.S. Nuclear Regulatory Commission, e-mail to Ken Nicely, Exelon Generation Company, LLC, "Clinton Nuclear Power Station – Request for Additional Information," dated October 27, 2020 (ADAMS Accession No. ML20307A659).

20 U.S. Nuclear Regulatory Commission, "EPRI/NRC Fire PRA Methodology for Nuclear Power Facilities," NUREG/CR-6850, September 2005 (ADAMS Accession No. ML052580075).

21 U.S. Nuclear Regulatory Commmission, "Fire Probabilistic Risk Assessment Methods Enhancement," NUREG/CR-6850, Supplement 1, September 2010 (ADAMS Accession No. ML203090242).

22 Giitter, J., U.S. Nuclear Regulatory Commission, letter to Biff Bradley, Nuclear Energy Institute, "Recent Fire PRA Methods Review Panel Decisions and EPRI 1022993, Evaluation of Peak Heat Release Rates in Eloectrical Cabinet Fires," dated June 21, 2012 (ADAMS Accession No. ML12171A583).

23 U.S. Nuclear Regulatory Commission, "Close-out of Fire PRA Frequently Asked Question 13-0004 on Clarification Regarding Treatment of Sensitive Electronics," FAQ 13-0004 , dated December 3, 2013 (ADAMS Accession No. ML13322A085).

24 Wiebe, J. S., U.S. Nuclear Regulatory Commission, e-mail to Ken Nicely, Exelon Generation Company, LLC, "Clarification of Second Round RAI – Clinton TSTF-505 License Amendment Request," dated February 26, 2021 (ADAMS Accession No. ML21057A101).

25 U.S. Nuclear Regulatory Commission, "EPRI/NRC-RES Fire Human Reliability Analysis Guidelines Final Report," NUREG-1921, July 2012 (ADAMS Accession No. ML12216A104).

26 U.S. Nuclear Regulatory Commission, "Good Practices for Implementing Human Reliability Analysis (HRA)," NUREG-1792, April 2005 (ADAMS Accession No. ML051160213).

27 U.S. Nuclear Regulatory Commisison, "Close-out of Fire PRA Frequently Asked Question 14-0009 on Treatment of Well-Sealed MCC Electrical Panels Greater Than 440V," FAQ 14-0009, dated April 29, 2015 (ADAMS Accession No. ML15114A441).

28 Kaegi, G.T., Exelon Generation Company, LLC, U.S. Nuclear Regulatory Commission, "Clinton Power Station Unit 1, Seismic Hazard and Screening Report (CEUS Sites), 'Response to NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding Recommendation 2.1 of the NTTF Review of the Fukushima DAi-ichi Accident'," dated March 31, 2014 (ADAMS Accession No. ML14091A011).

29 Barstow, J., Exelon Generation Company, LLC, letter to U.S. Nuclear Regulatory Commission, "Supplemental Information Regarding Seismic Hazard and Screening Report (Central and Eastern United States (CEUS) Sites - Response to NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding Recommendation 2.1," dated August 21, 2014 (ADAMS Accession No. ML14234A124).

30 U.S. Nuclear Regulatory Commission, "Results of Safety/Risk Assessment of Generic Issue 199, 'Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants'," dated September 2, 2010 (ADAMS Package Accession No. ML100270582).

31 Electric Power Research Institute, "Seismic Probabilistic Rick Assessment Implementation Guide," EPRI 3002000709, December 2013.

32 U.S. Nuclear Regulatory Commission, "Tornado Climatology of the Contiguous United States," NUREG/CR-4461, Revision 2, February 2007 (ADAMS Accession No. ML070810400).

33 U.S. Nuclear Regulatory Commission, "Tornado Missile Protection," NRC Regulatory Issue Summary (RIS) 2015-06, dated June 10, 2015 (ADAMS Accession No. ML15020A419).

34 U.S. Nuclear Regulatory Commmission, "Enforcement Discretion for Tornado-Generated Missile Protection Noncompliance," NRC Enforcement Guidance Memorandum (EGM) 15-002, June 10, 2015 (ADAMS Accession No. ML15111A269).

35 Exelon Generation Company, LLC, "Clinton Power Station Flood Hazard Reevaluation Report, Enclosure 1," dated March 12, 2014 (ADAMS Accession No. ML14079A420).

36 Govan, T., U.S. Nuclear Regulatory Commission, letter to Bryan Hanson, Exelon Generation Company, LLC, "Clinton Power Station, Unit No. 1 - Correction to Staff Assessment of Response to Request for Information Pursuant to 10 CFR 50.54(f) - Flood-Causing Mechanisms Reevalution (TAC NO. MF3654)," dated November 18, 2015 (ADAMS Accession No. ML15321A034).

37 Kaegi, G. T., Exelon Generation Company, LLC, letter to U.S. Nuclear Regulatory Commission, "Mitigating Strategies Flood Hazard Assessment (MSFHA) Submittal," dated March 24, 2016 (ML16084A859).

38 Vaughan, S., Nuclear Energy Institute, letter to U.S. Nuclear Regulatory Commission, "Submittal of NUMARC 93-01, Rev 4f, 'Industry Guideline for Monitoring the Effectiveness

of Maintenance at Nuclear Power Plants' for NRC Endorsement," dated April 27, 2018 (ADAMS Accession No. ML18120A069).

39 Reisi-Fard, M., memorandum to Joseph Giitter, U.S. Nuclear Regulatory Commission, "Assessment of The Nuclear Energy Institute 16-06, "Crediting Mitigating Strategies in Risk-Informed Decision Making," Guidance for Risk-Informed Changes to Plants Licensing Basis," dated May 30, 2017 (ADAMS Accession No. ML17031A269).

Principal Contributors: H. Wagage
J. Ashcraft
K. West
J. Evans
V. Goel
R. Vettori
K. Tetter

Date of issuance: June 28, 2021

SUBJECT: CLINTON POWER STATION, UNIT NO. 1 - ISSUANCE OF AMENDMENT NO. 238 RE: TECHNICAL SPECIFICATIONS TASK FORCE (TSTF 505), REVISION 2, "PROVIDE RISK INFORMED EXTENDED COMPLETION TIMES – RITSTF INITIATIVE 4B" (EPID L-2020-LLA-0097) DATED JUNE 28, 2021

DISTRIBUTION:
PUBLIC
PM File Copy
RidsACRS_MailCTR Resource
RidsNrrDorlLpl3 Resource
RidsNrrDexEeeb Resource
RidsNrrDexEicb Resource
RidsNrrDexEmib Resource
RidsNrrDraApla Resource
RidsNrrDraAplb Resource
RidsNrrDraAplc Resource
RidsNrrDssScpb Resource
RidsNrrDssStsb Resource
RidsNrrLASRohrer Resource
RidsNrrPMClinton Resource
RidsRgn3MailCenter Resource

ADAMS Accession No. ML21132A288

OFFICE	NRR/DORL/LPL3/PM	NRR/DORL/LPL3/LA	NRR/DSS/STSB/BC(A)	NRR/DSS/SCPB/BC
NAME	JWiebe	SRohrer	NJordan	BWittick
DATE	05/04/2021	05/20/2021	06/01/2021	06/01/2021
OFFICE	NRR/DEX/EICB/BC	NRR/DEX/EEEB/BC	NRR/DEX/EMIB/BC	NRR/DRA/APLA/BC
NAME	MWaters	BTitus	ABuford	RPascarelli
DATE	06/28/2021	01/21/2021	04/19/2021	04/28/2021
OFFICE	NRR/DRA/APLB/BC	NRR/DRA/APLC/BC	OGC	NRR/DORL/LPL3/BC
NAME	SRosenberg	SVasavada	STurk NLO	NSalgado
DATE	04/28/2021	04/28/2021	06/23/2021	06/28/2021
OFFICE	NRR/DORL/LPL3/PM			
NAME	JWiebe			
DATE	06/28/2021			

OFFICIAL RECORD COPY