September 7, 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: LASALLE COUNTY STATION, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 251 and 237 RE: REVISE TECHNICAL SPECIFICATIONS TO ADOPT RISK-INFORMED COMPLETION TIMES TSTF-505, REVISION 2, "PROVIDE RISK-INFORMED EXTENDED COMPLETION TIMES - RITSTF INITIATIVE 4B" (EPID L-2020-LLA-0018)

Dear Mr. Rhoades:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment Nos. 251 and 237 to Renewed Facility Operating License Nos. NPF-11 and NPF-18, for the LaSalle County Station, Unit Nos. 1 and 2, respectively. The amendments consist of changes to the technical specifications (TS) in response to your application dated January 31, 2020, as supplemented by letters dated October 1, 2020, October 29, 2020, March 31, 2021, and May 10, 2021. Publicly-available versions are in the Agencywide Documents Access and Management System (ADAMS) under Accession Nos. ML20035E577, ML20275A270, ML20303A307, ML21090A283, and ML21130A655, respectively).

The amendments modified TS requirements to permit the use of Risk-Informed Completion Times in accordance with Technical Specifications Task Force (TSTF) Traveler TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

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

Sincerely,

/RA/

Bhalchandra K. Vaidya, Project Manager
Plant Licensing Branch III
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-373 and 50-374

Enclosure:
1. Amendment No. 251 to NPF-11
2. Amendment No. 237 to NPF-18
3. Safety Evaluation

cc: Listserv

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-373

LASALLE COUNTY STATION, UNIT NO. 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 251
Renewed License No. NPF-11

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 January 31, 2020, as supplemented by letters dated October 1, 2020, October 29, 2020, March 31, 2021, and May 10, 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 paragraphs 2.C.(2) and 2.C.(48) of Renewed Facility Operating License No. NPF-11 are hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 251, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(48) Adoption of Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Exelon is approved to implement TSTF-505, Revision 2, modifying the Technical Specification requirements related to Completion Times (CT) for Required Actions to provide the option to calculate a longer, risk-informed CT (RICT). The methodology for using the new Risk-Informed Completion Time Program is described in NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, which was approved by the NRC on May 17, 2007.

Exelon will complete the implementation item listed in Attachment 5 of Exelon letter to the NRC dated January 31, 2020, prior to implementation of the RICT Program. All issues identified in the attachment will be addressed and any associated changes will be made, focused-scope peer reviews will be performed on changes that are PRA upgrades as defined in the PRA standard (ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, Revision 2), and any findings will be resolved and reflected in the PRA of record prior to implementation of the RICT Program.

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

FOR THE NUCLEAR REGULATORY COMMISSION

Nancy L. Salgado

Digitally signed by Nancy L. Salgado
Date: 2021.09.07 11:03:13 -04'00'

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

Attachment:
Changes to the Renewed Facility Operating License and Technical Specifications

Date of Issuance: September 7, 2021

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-374

LASALLE COUNTY STATION, UNIT NO. 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 237
Renewed License No. NPF-18

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 January 31, 2020, as supplemented by letters dated October 1, 2020, October 29, 2020, March 31, 2021, and May 10, 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 paragraphs 2.C.(2) and 2.C.(37) of Renewed Facility Operating License No. NPF-18 are hereby amended to read as follows:

    (2) Technical Specifications and Environmental Protection Plan

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 237, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

    (37) Adoption of Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

    Exelon is approved to implement TSTF-505, Revision 2, modifying the Technical Specification requirements related to Completion Times (CT) for Required Actions to provide the option to calculate a longer, risk-informed CT (RICT). The methodology for using the new Risk-Informed Completion Time Program is described in NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, which was approved by the NRC on May 17, 2007.

    Exelon will complete the implementation item listed in Attachment 5 of Exelon letter to the NRC dated January 31, 2020, prior to implementation of the RICT Program. All issues identified in the attachment will be addressed and any associated changes will be made, focused-scope peer reviews will be performed on changes that are PRA upgrades as defined in the PRA standard (ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, Revision 2), and any findings will be resolved and reflected in the PRA of record prior to implementation of the RICT Program.

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

FOR THE NUCLEAR REGULATORY COMMISSION

Nancy L. Salgado

Digitally signed by Nancy L. Salgado
Date: 2021.09.07 11:04:03 -04'00'

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

Attachment:
Changes to the Renewed Facility Operating License and Technical Specifications

Date of Issuance: September 7, 2021

ATTACHMENT TO LICENSE AMENDMENT NOS. 251 AND 237

RENEWED FACILITY OPERATING LICENSE NOS. NPF-11 AND NPF-18

LASALLE COUNTY STATION, UNITS 1 AND 2

DOCKET NOS. 50-373 AND 50-374

Replace the following pages of the Renewed Facility Operating Licenses and Appendix A, Technical Specifications, with the attached pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Renewed Facility Operating License No. NPF-11

REMOVE	INSERT
Page 3	Page 3
Page 11	Page 11
Page 12	Page 12
--	Page 13

Renewed Facility Operating License No. NPF-18

REMOVE	INSERT
Page 3	Page 3
Page 11	Page 11
Page 12	Page 12
--	Page 13

Technical Specifications

Replace the following pages of Appendix A in License No. NPF-11, 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
TS 1.3-13	TS 1.3-13
--	TS 1.3-14
TS 3.1.7-1	TS 3.1.7-1
TS 3.1.7-2	TS 3.1.7-2
TS 3.3.1.1-1	TS 3.3.1.1-1
TS 3.3.1.1-2	TS 3.3.1.1-2
TS 3.3.2.2-1	TS 3.3.2.2-1
TS 3.3.4.2-1	TS 3.3.4.2-1
TS 3.3.4.2-2	TS 3.3.4.2-2
TS 3.3.5.1-2	TS 3.3.5.1-2
TS 3.3.5.1-3	TS 3.3.5.1-3

REMOVE	INSERT
TS 3.3.5.1-4	TS 3.3.5.1-4
TS 3.3.5.1-5	TS 3.3.5.1-5
TS 3.3.5.1-6	TS 3.3.5.1-6
TS 3.3.5.1-7	TS 3.3.5.1-7
TS 3.3.5.1-8	TS 3.3.5.1-8
TS 3.3.5.1-9	TS 3.3.5.1-9
TS 3.3.5.1-10	TS 3.3.5.1-10
TS 3.3.5.1-11	TS 3.3.5.1-11
TS 3.3.5.1-12	TS 3.3.5.1-12
--	TS 3.3.5.1-13
--	TS 3.3.5.1-14
TS 3.3.5.3-1	TS 3.3.5.3-1
TS 3.3.5.3-2	TS 3.3.5.3-2
TS 3.3.5.3-3	TS 3.3.5.3-3
TS 3.3.5.3-4	TS 3.3.5.3-4
--	TS 3.3.5.3-5
TS 3.3.6.1-1	TS 3.3.6.1-1
TS 3.3.6.1-2	TS 3.3.6.1-2
TS 3.3.6.1-3	TS 3.3.6.1-3
TS 3.3.8.1-1	TS 3.3.8.1-1
TS 3.5.1-1	TS 3.5.1-1
TS 3.5.1-2	TS 3.5.1-2
TS 3.5.1-3	TS 3.5.1-3
TS 3.5.3-1	TS 3.5.3-1
TS 3.6.1.2-4	TS 3.6.1.2-4
--	TS 3.6.1.2-5
TS 3.6.1.3-1	TS 3.6.1.3-1
TS 3.6.1.3-2	TS 3.6.1.3-2
TS 3.6.1.3-4	TS 3.6.1.3-4
TS 3.6.1.6-1	TS 3.6.1.6-1
TS 3.6.1.6-2	TS 3.6.1.6-2
TS 3.6.2.3-1	TS 3.6.2.3-1
TS 3.6.2.4-1	TS 3.6.2.4-1
TS 3.7.1-1	TS 3.7.1-1
TS 3.8.1-2	TS 3.8.1-2
TS 3.8.1-3	TS 3.8.1-3
TS 3.8.1-4	TS 3.8.1-4
TS 3.8.1-5	TS 3.8.1-5
TS 3.8.1-6	TS 3.8.1-6
TS 3.8.1-6a	TS 3.8.1-6a
TS 3.8.1-7	TS 3.8.1-7
TS 3.8.1-8	TS 3.8.1-8
TS 3.8.1-9	TS 3.8.1-9
TS 3.8.1-10	TS 3.8.1-10
TS 3.8.1-11	TS 3.8.1-11
TS 3.8.1-12	TS 3.8.1-12
TS 3.8.1-13	TS 3.8.1-13
TS 3.8.1-14	TS 3.8.1-14
TS 3.8.1-15	TS 3.8.1-15

REMOVE	INSERT
TS 3.8.1-16	TS 3.8.1-16
TS 3.8.1-17	TS 3.8.1-17
TS 3.8.1-18	TS 3.8.1-18
TS 3.8.1-19	TS 3.8.1-19
--	TS 3.8.1-20
TS 3.8.4-1	TS 3.8.4-1
TS 3.8.4-2	TS 3.8.4-2
TS 3.8.4-3	TS 3.8.4-3
TS 3.8.4-4	TS 3.8.4-4
TS 3.8.7-1	TS 3.8.7-1
TS 3.8.7-2	TS 3.8.7-2
TS 3.8.7-3	TS 3.8.7-3
TS 5.5-16	TS 5.5-16
--	TS 5.5-17

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

Am. 146
01/12/01

(4) Exelon Generation Company, LLC, 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; and

Am. 202
07/21/11

(5) Exelon Generation Company, LLC, 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 LaSalle County Station, Units 1 and 2, and such Class B and Class C low-level radioactive waste as may be produced by the operation of Braidwood Station, Units 1 and 2, Byron Station, Units 1 and 2, and Clinton Power Station, Unit 1.

C. This renewed 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:

Am. 198
09/16/10

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of full power (3546 megawatts thermal).

Am. 251
07/xx/21

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 251, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the renewed license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

Am. 194
08/28/09

(3) DELETED

Am. 194
08/28/09

(4) DELETED

Am. 194
08/28/09

(5) DELETED

Am. 251
07/XX/21

(48) Adoption of Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times -RITSTF Initiative 4b"

Exelon is approved to implement TSTF-505, Revision 2, modifying the Technical Specification requirements related to Completion Times (CT) for Required Actions to provide the option to calculate a longer, risk-informed CT (RICT). The methodology for using the new Risk-Informed Completion Time Program is described in NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, which was approved by the NRC on May 17, 2007.

Exelon will complete the implementation item listed in Attachment 5 of Exelon letter to the NRC dated January 31, 2020, prior to implementation of the RICT Program. All issues identified in the attachment will be addressed and any associated changes will be made, focused-scope peer reviews will be performed on changes that are PRA upgrades as defined in the PRA standard (ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, Revision 2), and any findings will be resolved and reflected in the PRA of record prior to implementation of the RICT Program.

Am. 102
03/16/95

D. The facility requires exemptions from certain requirements of 10 CFR Part 50, 10 CFR Part 70, and 10 CFR Part 73. These include:

(a) Exemptions from certain requirements of Appendices G, H and J and 10 CFR Part 73 are described in the Safety Evaluation Report and Supplement No. 1, No. 2, No. 3 to the Safety Evaluation Report.

(b) DELETED

(c) DELETED

(d) DELETED

Am. 226
11/16/17

(e) DELETED

Am. 112
04/05/96

(f) An exemption was granted to remove the Main Steam Isolation Valves (MSIVs) from the acceptance criteria for the combined local leak rate test (Type B and C), as defined in the regulations of 10 CFR Part 50, Appendix J, Option B, Paragraph III.B. Exemption (f) is described in the safety evaluation accompanying Amendment No. 112 to this License.

These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. Therefore, these exemptions are hereby granted. The facility will operate, to the extent authorized herein, in conformity with the application, as amended, and the rules and regulations of the Commission (except as hereinafter exempted there from), and the provisions of the Act.

E. This renewed license is subject to the following additional condition for the protection of the environment:

Before engaging in additional construction or operational activities which may result in a significant adverse environmental impact that was not evaluated or that is significantly greater than that evaluated in the Final Environmental Statement and its Addendum dated November 1978, and the Final Supplemental Environmental Impact Statement dated August 2016, the licensee shall provide a written notification to the Director of the Office of Nuclear Reactor Regulation and receive written approval from that office before proceeding with such activities.

Am. 178
06/14/06

F. Deleted

G. The licensee shall have and maintain financial protection of such type and in such amounts as the Commission shall require in accordance with Section 170 of the Atomic Energy Act of 1954, as amended, to cover public liability claims.

H. This renewed license is effective as of the date of issuance and shall expire April 17, 2042.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

WILLIAM M. DEAN, DIRECTOR
OFFICE OF NUCLEAR REACTOR REGULATION

Am. 194 08/28/09 Attachments:
1. DELETED
2. Appendix A – Technical Specifications (NUREG-0861)
3. Appendix B – Environmental Protection Plan

Date of Issuance: October 19, 2016

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

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

(4) 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; and

Am. 189
07/21/11

(5) Exelon Generation Company, LLC, 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 LaSalle County Station, Units 1 and 2, and such Class B and Class C low-level radioactive waste as may be produced by the operation of Braidwood Station, Units 1 and 2, Byron Station, Units 1 and 2, and Clinton Power Station, Unit 1.

C. This renewed 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:

Am. 185
09/16/10

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of full power (3546 megawatts thermal). Items in Attachment 1 shall be completed as specified. Attachment 1 is hereby incorporated into this license.

Am. 237
07/xx/21

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 237, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the renewed license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

Am. 237
07/xx/21

(37) Adoption of Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times -RITSTF Initiative 4b"

Exelon is approved to implement TSTF-505, Revision 2, modifying the Technical Specification requirements related to Completion Times (CT) for Required Actions to provide the option to calculate a longer, risk-informed CT (RICT). The methodology for using the new Risk-Informed Completion Time Program is described in NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, which was approved by the NRC on May 17, 2007.

Exelon will complete the implementation item listed in Attachment 5 of Exelon letter to the NRC dated January 31, 2020, prior to implementation of the RICT Program. All issues identified in the attachment will be addressed and any associated changes will be made, focused-scope peer reviews will be performed on changes that are PRA upgrades as defined in the PRA standard (ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, Revision 2), and any findings will be resolved and reflected in the PRA of record prior to implementation of the RICT Program.

Am. 87 03/16/95

D. The facility requires exemptions from certain requirements of 10 CFR Part 50, 10 CFR Part 70, and 10 CFR Part 73. These include:

(a) Exemptions from certain requirements of Appendices G, H and J to 10 CFR Part 50, and to 10 CFR Part 73 are described in the Safety Evaluation Report and Supplement Numbers 1, 2, 3, and 5 to the Safety Evaluation Report.

Am. 181 08/28/09

(b) DELETED

Am. 212 11/16/17

(c) DELETED

Am. 181 08/28/09

(d) DELETED

Am. 97 04/05/96

(e) An exemption was granted to remove the Main Steam Isolation Valves (MSIVs) from the acceptance criteria for the combined local leak rate test (Type B and C), as defined in the regulations of 10 CFR Part 50, Appendix J, Option B, Paragraph III.B. Exemption (e) is described in the safety evaluation accompanying Amendment No. 97 to this License.

These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. Therefore, these exemptions are hereby granted. The facility will operate, to the extent authorized herein, in conformity with the application, as amended, and the rules and regulations of the Commission (except as hereinafter exempted therefrom), and the provisions of the Act.

E. Before engaging in additional construction or operational activities which may result in a significant adverse environmental impact that was not evaluated or that is significantly greater than that evaluated in the Final Environmental Statement and its Addendum dated November 1978, and the Final Supplemental Environmental Impact Statement dated September 2016, the licensee shall provide a written notification to the Director of the Office of Nuclear Reactor Regulation and receive written approval from that office before proceeding with such activities.

Am. 164 06/14/06 F. Deleted

Am. 164 06/14/06 G. Deleted

H. The licensee shall have and maintain financial protection of such type and in such amounts as the Commission shall require in accordance with Section 170 of the Atomic Energy Act of 1954, as amended, to cover public liability claims.

I. This renewed license is effective as of the date of issuance and shall expire at Midnight on December 16, 2043.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

WILLIAM M. DEAN, DIRECTOR
OFFICE OF NUCLEAR REACTOR REGULATION

Attachments:
1. DELETED
2. DELETED
3. Appendix A – Technical Specifications (NUREG-1013)
4. Appendix B – Environmental Protection Plan

Date of Issuance: October 19, 2016

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-7 (continued)

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

EXAMPLE 1.3-8 (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, Conditions A and B are exited, and therefore, the Required Actions of Condition B may be terminated.

IMMEDIATE COMPLETION TIME

When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

3.1 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
SR 3.1.7.2	Verify temperature of sodium pentaborate solution is within the limits of Figure 3.1.7-2.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.2	Verify temperature of sodium pentaborate solution is within the limits of Figure 3.1.7-2.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.3	Verify temperature of pump suction piping up to the storage tank outlet valves is ≥ 68°F.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.4	Verify continuity of explosive charge.	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 channel.

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 ≥ 25% 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 required channels inoperable.	A.1 Place channel in trip.	12 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>OR</u>	
	A.2 Place associated trip system in trip.	12 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One or more Functions with one or more required channels inoperable in both trip systems.	B.1	Place channel in one trip system in trip.	6 hours OR In accordance with the Risk Informed Completion Time Program
	OR		
	B.2	Place one trip system in trip.	6 hours OR In accordance with the Risk Informed Completion Time Program
C. One or more Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
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 < 25% RTP.	4 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS 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 RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.2	------------------NOTE------------------ Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. -- Verify the calculated power does not exceed the average power range monitor (APRM) channels by greater than 2% RTP while operating at ≥ 25% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.3	Adjust the channel to conform to a calibrated flow signal.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.4	-------------------NOTE------------------- Not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.6	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to fully withdrawing SRMs
SR 3.3.1.1.7	-------------------NOTE------------------- Only required to be met during entry into MODE 2 from MODE 1. -- Verify the IRM and APRM channels overlap.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.8	Calibrate the local power range monitors.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.9	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.10	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.11	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.13	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 1.a, not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.14	Verify the APRM Flow Biased Simulated Thermal Power—Upscale time constant is ≤ 7 seconds.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.16	Verify Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ 25% RTP.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.17	-------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 9, the RPS RESPONSE TIME is measured from start of turbine control valve fast closure. -- Verify the RPS RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux—High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 123/125 divisions of full scale
	5[(a)]	3	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 123/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.4 SR 3.3.1.1.15	NA
	5[(a)]	3	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
2. Average Power Range Monitors					
a. Neutron Flux—High, Setdown	2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.15	≤ 20% RTP
b. Flow Biased Simulated Thermal Power—Upscale	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.11[(b)(c)] SR 3.3.1.1.14 SR 3.3.1.1.15	≤ 0.61 W + 68.2% RTP and ≤ 115.5% RTP[(d)]
c. Fixed Neutron Flux-High	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.11 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ 120% RTP

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.
(b) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(c) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the nominal trip setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the NTSP are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the surveillance procedures (field setting) to confirm channel performance. The NTSP and the methodologies used to determine the as-found and the as-left tolerances are specified in the Technical Requirements Manual.
(d) Allowable Value is ≤ 0.54 W + 55.9% RTP and ≤ 112.3% RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

Table 3.3.1.1-1 (page 2 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Average Power Range Monitors (continued)					
d. Inop	1,2	2	G	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.15	NA
3. Reactor Vessel Steam Dome Pressure—High	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.15	≤ 1059.0 psig
4. Reactor Vessel Water Level-Low, Level 3	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17	≥ 11.0 inches
5. Main Steam Isolation Valve-Closure	1	8	F	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ 13.7% closed
6. Drywell Pressure—High	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 1.93 psig
7. Scram Discharge Volume Water Level—High					
a. Transmitter/Trip Unit	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 767 ft 8.55 inches elevation
	5[(a)]	2	H	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 767 ft 8.55 inches elevation

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

Table 3.3.1.1-1 (page 3 of 3)
Reactor Protection System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7.	Scram Discharge Volume Water Level—High (continued)					
	b. Float Switch	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 767 ft 8.55 inches elevation
		5[(a)]	2	H	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 767 ft 8.55 inches elevation
8.	Turbine Stop Valve—Closure	≥ 25% RTP	4	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 8.9% closed
9.	Turbine Control Valve Fast Closure, Trip Oil Pressure—Low	≥ 25% RTP	2	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≥ 425.5 psig
10.	Reactor Mode Switch-Shutdown Position	1,2	2	G	SR 3.3.1.1.12 SR 3.3.1.1.15	NA
		5[(a)]	2	H	SR 3.3.1.1.12 SR 3.3.1.1.15	NA
11.	Manual Scram	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
		5[(a)]	2	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

3.3 INSTRUMENTATION

3.3.2.2 Feedwater System and Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Four channels of feedwater system and main turbine high water level trip instrumentation shall be OPERABLE.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more feedwater system and main turbine high water level trip channels inoperable.	A.1 Place channel in trip.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Feedwater system and main turbine high water level trip capability not maintained.	B.1 Restore feedwater system and main turbine high water level trip capability.	2 hours

(continued)

3.3 INSTRUMENTATION

3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

LCO 3.3.4.2 Two channels per trip system for each ATWS-RPT instrumentation Function listed below shall be OPERABLE:

a. Reactor Vessel Water Level—Low Low, Level 2; and

b. Reactor Steam Dome Pressure—High.

APPLICABILITY: MODE 1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status.	14 days <u>OR</u> In accordance with the Risk Informed Completion Time Program (continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	<u>OR</u>		
	A.2	--------NOTE--------- Not applicable if inoperable channel is the result of an inoperable breaker. --------------------- Place channel in trip.	14 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. One Function with ATWS-RPT trip capability not maintained.	B.1	Restore ATWS-RPT trip capability.	72 hours
C. Both Functions with ATWS-RPT trip capability not maintained.	C.1	Restore ATWS-RPT trip capability for one Function.	1 hour
D. Required Action and associated Completion Time not met.	D.1	Remove the associated recirculation pump from service.	6 hours
	<u>OR</u>		
	D.2	Be in MODE 2.	6 hours

ACTIONS

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 a loss of function occurs. -------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

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 and 2.c. --------------------- 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		
	C.2	Restore channel to OPERABLE status.	24 hours OR -----NOTE----- Not applicable when a loss of function occurs. -------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

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 for Functions 1.d, 1.e, 1.f, 1.g, 2.d, 2.e, and 2.f. ---------------------	
		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>		
	D.2	--------NOTE--------- Only applicable for Functions 1.d and 2.d. ---------------------	
		Declare supported feature(s) inoperable.	24 hours from discovery of loss of initiation capability for feature(s) in one division
	<u>AND</u>		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. (continued)	D.3	--------NOTE--------- Only applicable for Functions 1.g and 2.f. --------------------- Restore channel to OPERABLE status.	24 hours <u>OR</u> -----NOTE----- Not applicable when a loss of function occurs. -------------- In accordance with the Risk Informed Completion Time Program
	<u>AND</u>		
	D.4	Restore channel to OPERABLE status.	7 days <u>OR</u> -----NOTE----- Not applicable when a loss of function occurs. -------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	E.1	Declare Automatic Depressurization System (ADS) valves inoperable.	1 hour from discovery of loss of ADS initiation capability in both trip systems
	<u>AND</u>		
	E.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 a loss of function occurs. --------------- 8 days or in accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	F.1	--------NOTE--------- 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 (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. (continued)	<u>AND</u> F.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 <u>AND</u> -----NOTE----- The Risk Informed Completion Time Program is not applicable when a loss of function occurs. --------------- 8 days or in accordance with the Risk Informed Completion Time Program
G. Required Action and associated Completion Time of Condition B, C, D, E, or F not met.	G.1 Declare associated supported feature(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

-- NOTES --

1. Refer to Table 3.3.5.1-1 to determine which SRs apply for each ECCS 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 as follows: (a) for up to 6 hours for Functions 3.c, 3.d, 3.e, and 3.f; and (b) for up to 6 hours for Functions other than 3.c, 3.d, 3.e, and 3.f, provided the associated Function or the redundant Function maintains ECCS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.6	Verify ECCS RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program

Table 3.3.5.1–1 (page 1 of 4)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Low Pressure Coolant Injection-A (LPCI) and Low Pressure Core Spray (LPCS) Subsystems					
a. Reactor Vessel Water Level—Low Low Low, Level 1	1,2,3	2[a]	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ -147.0 inches
b. Drywell Pressure—High	1,2,3	2[a]	B	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.6	≤ 1.77 psig
c. LPCI Pump A Start—Time Delay Relay	1,2,3	1	C	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 5.5 seconds
d. Reactor Steam Dome Pressure—Low (Injection Permissive)	1,2,3	2	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 490 psig and ≤ 522 psig
e. LPCS Pump Discharge Flow—Low (Bypass)	1,2,3	1	D	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 1240 gpm and ≤ 1835 gpm
f. LPCI Pump A Discharge Flow—Low (Bypass)	1,2,3	1	D	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 1330 gpm and ≤ 2144 gpm
g. LPCS and LPCI A Injection Line Pressure—Low (Injection Permissive)	1,2,3	1 per valve	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 490 psig and ≤ 522 psig
h. Manual Initiation	1,2,3	1	C	SR 3.3.5.1.5	NA

(continued)

(a) Also required to initiate the associated diesel generator (DG).

Table 3.3.5.1-1 (page 2 of 4)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. LPCI B and LPCI C Subsystems					
a. Reactor Vessel Water Level—Low Low Low, Level 1	1,2,3	2[a]	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ -147.0 inches
b. Drywell Pressure—High	1,2,3	2[a]	B	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.6	≤ 1.77 psig
c. LPCI Pump B Start—Time Delay Relay	1,2,3	1	C	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 5.5 seconds
d. Reactor Steam Dome Pressure—Low (Injection Permissive)	1,2,3	2	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 490 psig and ≤ 522 psig
e. LPCI Pump B and LPCI Pump C Discharge Flow—Low (Bypass)	1,2,3	1 per pump	D	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 1330 gpm and ≤ 2144 gpm
f. LPCI B and LPCI C Injection Line Pressure—Low (Injection Permissive)	1,2,3	1 per valve	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ 490 psig and ≤ 522 psig
g. Manual Initiation	1,2,3	1	C	SR 3.3.5.1.5	NA

(continued)

(a) Also required to initiate the associated DG.

Table 3.3.5.1-1 (page 3 of 4)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. High Pressure Core Spray (HPCS) System					
a. Reactor Vessel Water Level—Low Low, Level 2	1,2,3	4[(a)]	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.6	≥ -83 inches
b. Drywell Pressure—High	1,2,3	4[(a)]	B	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.6	≤ 1.77 psig
c. Reactor Vessel Water Level—High, Level 8	1,2,3	2	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 66.5 inches
d. HPCS Pump Discharge Pressure—High (Bypass)	1,2,3	1	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 113.2 psig
e. HPCS System Flow Rate—Low (Bypass)	1,2,3	1	D	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 1380 gpm and ≤ 2194 gpm
f. Manual Initiation	1,2,3	1	C	SR 3.3.5.1.5	NA
4. Automatic Depressurization System (ADS) Trip System A					
a. Reactor Vessel Water Level—Low Low Low, Level 1	1,2[(b)],3[(b)]	2	E	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -147.0 inches
b. Drywell Pressure—High	1,2[(b)],3[(b)]	2	E	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 1.77 psig
c. ADS Initiation Timer	1,2[(b)],3[(b)]	1	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 118 seconds

(continued)

(a) Also required to initiate the associated DG.

(b) With reactor steam dome pressure > 150 psig.

Table 3.3.5.1-1 (page 4 of 4)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. ADS Trip System A (continued)					
d. Reactor Vessel Water Level—Low, Level 3 (Confirmatory)	1,2(b),3(b)	1	E	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 11.0 inches
e. LPCS Pump Discharge Pressure—High	1,2(b),3(b)	2	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 131.2 psig and ≤ 271.0 psig
f. LPCI Pump A Discharge Pressure—High	1,2(b),3(b)	2	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 105.0 psig and ≤ 128.6 psig
g. ADS Drywell Pressure Bypass Timer	1,2(b),3(b)	2	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 598 seconds
h. Manual Initiation	1,2(b),3(b)	2	F	SR 3.3.5.1.5	NA
5. ADS Trip System B					
a. Reactor Vessel Water Level—Low Low Low, Level 1	1,2(b),3(b)	2	E	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -147.0 inches
b. Drywell Pressure—High	1,2(b),3(b)	2	E	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 1.77 psig
c. ADS Initiation Timer	1,2(b),3(b)	1	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 118 seconds
d. Reactor Vessel Water Level—Low, Level 3 (Confirmatory)	1,2(b),3(b)	1	E	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 11.0 inches
e. LPCI Pumps B & C Discharge Pressure—High	1,2(b),3(b)	2 per pump	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 105.0 psig and ≤ 128.6 psig
f. ADS Drywell Pressure Bypass Timer	1,2(b),3(b)	2	F	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 598 seconds
g. Manual Initiation	1,2(b),3(b)	2	F	SR 3.3.5.1.5	NA

(b) With reactor steam dome pressure > 150 psig.

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.	1 hour from discovery of loss of RCIC initiation capability

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND B.2 Place channel in trip.	24 hours OR -----NOTE----- Not applicable when a loss of function occurs. -------------- In accordance with the Risk Informed Completion Time Program
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

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
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 a loss of function occurs. -------------- 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

SURVEILLANCE REQUIREMENTS

-----------------------------------NOTES-----------------------------------
-
1. Refer to Table 3.3.5.3-1 to determine which SRs apply for each RCIC 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 as follows: (a) for up to 6 hours for Functions 2 and 4; and (b) for up to 6 hours for Functions 1 and 3 provided the associated Function maintains RCIC initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.3.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.5.3-1 (page 1 of 1)
Reactor Core Isolation Cooling System Instrumentation

FUNCTION	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level—Low Low, Level 2	4	B	SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.4	≥ -83 inches
2. Reactor Vessel Water Level—High, Level 8	2	C	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.4	≤ 66.5 inches
3. Condensate Storage Tank Level—Low	2	D	SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.4	≥ 713.6 ft
4. Manual Initiation	1	C	SR 3.3.5.3.4	NA

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

LCO 3.3.6.1 The primary containment 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

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

1. Separate Condition entry is allowed for each channel.
2. For Function 1.e, when automatic isolation capability is inoperable for required Reactor Building Ventilation System corrective maintenance, filter changes, damper cycling, or required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 4 hours.
3. For Function 1.e, when automatic isolation capability is inoperable due to loss of reactor building ventilation or for performance of SR 3.6.4.1.3 or SR 3.6.4.1.4, entry into associated Conditions and Required Action may be delayed for up to 12 hours.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Place channel in trip.	12 hours or in accordance with the Risk Informed Completion Time Program for Functions 2.b, 2.f, and 5.a (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)		AND 24 hours or in accordance with the Risk Informed Completion Time Program for Functions other than Functions 2.b, 2.f, and 5.a
B. One or more automatic Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately
D. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	D.1 Isolate associated main steam line (MSL). OR D.2.1 Be in MODE 3. AND D.2.2 Be in MODE 4.	12 hours 12 hours 36 hours
E. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	E.1 Be in MODE 2.	6 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	F.1 Isolate the affected penetration flow path(s).	1 hour
G. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	G.1 Isolate the affected penetration flow path(s).	24 hours
H. Required Action and associated Completion Time of Condition F or G not met. <u>OR</u> As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	H.1 Be in MODE 3. <u>AND</u> H.2 Be in MODE 4.	12 hours 36 hours
I. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	I.1 Declare associated standby liquid control (SLC) subsystem inoperable. <u>OR</u> I.2 Isolate the Reactor Water Cleanup (RWCU) System.	1 hour 1 hour

(continued)

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.	1 hour <u>OR</u> -----NOTE------ Not applicable when a loss of function occurs. --------------- 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

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 six safety/relief valves shall be OPERABLE.

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 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 <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. High Pressure Core Spray (HPCS) System inoperable.	B.1	Verify by administrative means RCIC System is OPERABLE when RCIC is required to be OPERABLE.	Immediately
	<u>AND</u>		
	B.2	Restore HPCS System to OPERABLE status.	14 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. Two low pressure ECCS injection/spray subsystems inoperable.	C.1	Restore one low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Be in MODE 3.	12 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. One required ADS valve inoperable.	E.1	Restore required ADS valve to OPERABLE status.	14 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
F. Required Action and associated Completion Time of Condition E not met.	F.1	Be in MODE 3.	12 hours
G. Two or more required ADS valves inoperable. <u>OR</u> ADS accumulator backup compressed gas system inoperable.	G.1 <u>AND</u> G.2	Be in MODE 3. Reduce reactor steam dome pressure to $\leq$ 150 psig.	12 hours 36 hours
H. HPCS and one or more low pressure ECCS injection/spray subsystems inoperable. <u>OR</u> Three or more ECCS injection/spray subsystems inoperable. <u>OR</u> One or more ECCS injection/spray subsystems and one or more required ADS valves inoperable.	H.1	Enter LCO 3.0.3.	Immediately

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.	Immediately
	<u>AND</u>	
	A.2 Restore RCIC System to OPERABLE status.	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.	12 hours
	<u>AND</u>	
	B.2 Reduce reactor steam dome pressure to ≤ 150 psig.	36 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.3 Restore air lock to OPERABLE status.	24 hours OR In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.1	------------------NOTES------------------ 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1.1. --- Perform required primary containment air lock leakage rate testing in accordance with the Primary Containment Leakage Rate Testing Program.	In accordance with the Primary Containment Leakage Rate Testing Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.2	Verify only one door in the primary containment air lock can be opened at a time.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ---------NOTE--------- Only applicable to penetration flow paths with two or more PCIVs. ---------------------- One or more penetration flow paths with one PCIV inoperable for reasons other than Condition D.	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 <u>AND</u> 8 hours or in accordance with the Risk Informed Completion Time Program for main steam line (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	AND A.2 --------NOTES-------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by 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 primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. (continued)	C.2	-------NOTES-------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. --------------------- Verify the affected penetration flow path is isolated.	 Once per 31 days following isolation
D. One or more penetration flow paths with MSIV leakage rate or hydrostatically tested line leakage rate not within limit.	D.1	Restore leakage rate to within limit.	4 hours for hydrostatically tested line leakage not on a closed system <u>AND</u> 8 hours for MSIV leakage <u>AND</u> 72 hours for hydrostatically tested line leakage on a closed system

(continued)

3.6 CONTAINMENT SYSTEMS

3.6.1.6 Suppression Chamber-to-Drywell Vacuum Breakers

LCO 3.6.1.6 Each suppression chamber-to-drywell vacuum breaker shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One suppression chamber-to-drywell vacuum breaker inoperable for opening.	A.1 Restore the vacuum breaker to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3.	12 hours
C. One suppression chamber-to-drywell vacuum breaker not closed.	C.1 Close both manual isolation valves in the affected line. <u>AND</u> C.2 Restore the vacuum breaker to OPERABLE status.	4 hours 72 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours
E. Two or more suppression chamber-to-drywell vacuum breakers inoperable.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.1	------------------NOTES------------------ 1. Not required to be met for vacuum breakers that are open during Surveillances. 2. Not required to be met for vacuum breakers open when performing their intended function. --- Verify each vacuum breaker is closed.	In accordance with the Surveillance Frequency Control Program

(continued)

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.

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 OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	B. Be in MODE 3.	12 hours
C. Two RHR suppression pool cooling subsystems inoperable.	C.1 Restore one RHR suppression pool cooling subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

LCO 3.6.2.4 Two RHR suppression pool spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR suppression pool spray subsystem inoperable.	A.1	Restore RHR suppression pool spray subsystem to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Two RHR suppression pool spray subsystems inoperable.	B.1	Restore one RHR suppression pool spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	12 hours

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System

LCO 3.7.1 Two RHRSW subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

(continued)

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	A.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one division concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	A.3	Restore required offsite circuit to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required Division 1, or 2 DG inoperable. <u>OR</u> Required opposite unit Division 2 DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	B.2	Declare required feature(s), supported by the inoperable DG(s), inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	B.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	<u>OR</u>		
	B.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	<u>AND</u>		
	B.4	Restore required DG(s) to OPERABLE status.	14 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. --------NOTE--------- 1. Not applicable to the Division 2 DG and the opposite unit Division 2 DG during installation of Division 2 CSCS isolation valves during a single Unit 1 Refueling Outage completed prior to July 1, 2024, and during a single Unit 2 Refueling Outage completed prior to July 1, 2023, while the outage unit is in MODE 4,5, or defueled. --------------------- Required Division 3 DG inoperable. <u>OR</u> One required Division 1, 2, or 3 DG inoperable and the required opposite unit Division 2 DG inoperable.	C.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	C.2	Declare required feature(s), supported by the inoperable DG(s), inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	C.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	<u>OR</u>		
	C.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. (continued)	AND		
	C.4	Restore required DG(s) to OPERABLE status.	72 hours OR -----NOTE------ Not applicable when a loss of function occurs. --------------- In accordance with the Risk Informed Completion Time Program
D. Two required offsite circuits inoperable.	D.1	Declare required feature(s) inoperable when the redundant required feature(s) are inoperable.	12 hours from discovery of Condition D concurrent with inoperability of redundant required feature(s)
	AND		
	D.2	Restore one required offsite circuit to OPERABLE status.	24 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One required offsite circuit inoperable. AND One required Division 1, 2, or 3 DG inoperable.	------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems—Operating," when Condition E is entered with no AC power source to any required division. -----------------------------	
	E.1 Restore required offsite circuit to OPERABLE status.	12 hours OR In accordance with the Risk Informed Completion Time Program
	OR	
	E.2 Restore required DG to OPERABLE status.	12 hours OR In accordance with the Risk Informed Completion Time Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. --------NOTE--------- 1. Not applicable during installation of the Division 2 CSCS isolation valves during a single Unit 1 Refueling Outage completed prior to July 1, 2024, and during a single Unit 2 Refueling Outage completed prior to July 1, 2023, while the outage unit is in MODE 4,5, or defueled. --------------------- Two required Division 1, 2, or 3 DGs inoperable. <u>OR</u> Division 2 DG and the required opposite unit Division 2 DG inoperable.	F.1 Restore one required DG to OPERABLE status.	2 hours <u>OR</u> 72 hours if Division 3 DG is inoperable

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
G. --------NOTE---------- 1. Only applicable during installation of Division 2 CSCS isolation valves during a single Unit 1 Refueling Outage completed prior to July 1, 2024, and during a single Unit 2 Refueling Outage completed prior to July 1, 2023, while the outage unit is in MODE 4,5, or defueled. --------------------- Division 2 DG and the required opposite unit Division 2 DG inoperable.	G.1	Restore required Division 2 DG to OPERABLE status.	7 days
H. Required Action and associated Completion Time of Condition A, B, C, D, E, F or G not met.	H.1	Be in MODE 3.	12 hours
I. Three or more required AC sources inoperable.	I.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTES ------------------------------------
1. SR 3.8.1.1 through SR 3.8.1.20 are applicable only to the given unit's AC electrical power sources.

2. SR 3.8.1.21 is applicable to the required opposite unit's DG.

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.2	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 2. 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. 3. A single test of the common DG at the specified Frequency will satisfy the Surveillance for both units. --- Verify each required DG starts from standby conditions and achieves steady state voltage ≥ 4010 V and ≤ 4310 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	 In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	-------------------NOTES------------------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by, and immediately follow, without shutdown, a successful performance of SR 3.8.1.2 or SR 3.8.1.7. 5. A single test of the common DG at the specified Frequency will satisfy the Surveillance for both units. --- Verify each required DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 2400 kW and ≤ 2600 kW.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.4	Verify each required day tank contains ≥ 250 gal of fuel oil for Divisions 1 and 2 and ≥ 550 gal for Division 3.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.5	Check for and remove accumulated water from each required day tank.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	Verify each required fuel oil transfer system operates to automatically transfer fuel oil from storage tanks to the day tank.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.7	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. A single test of the common DG at the specified Frequency will satisfy the Surveillance for both units. --- Verify each required DG starts from standby condition and achieves: a. In ≤ 13 seconds, voltage ≥ 4010 V and frequency ≥ 58.8 Hz; and b. Steady state voltage ≥ 4010 V and ≤ 4310 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.8	-------------------NOTE-------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	-------------------NOTES------------------- 1. This Surveillance shall not normally be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. 2. A single test of the common DG at the specified Frequency will satisfy the Surveillance for both units. --- Verify each required DG rejects a load greater than or equal to its associated single largest post-accident load and following load rejection, the frequency is ≤ 66.7 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.10	-------------------NOTES------------------- 1. This Surveillance shall not normally be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. 2. A single test of the common DG at the specified Frequency will satisfy the Surveillance for both units. --- Verify each required DG does not trip and voltage is maintained ≤ 5000 V during and following a load rejection of a load ≥ 2600 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2 only; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 13 seconds, 2. energizes auto-connected shutdown loads, 3. maintains steady state voltage ≥ 4010 V and ≤ 4310 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each required DG auto-starts from standby condition and: a. In ≤ 13 seconds after auto-start, achieves voltage ≥ 4010 V and frequency ≥ 58.8 Hz; b. Achieves steady state voltage ≥ 4010 V and ≤ 4310 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	-------------------NOTE------------------- This Surveillance shall not normally be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. -- Verify each required DG's automatic trips are bypassed on an actual or simulated ECCS initiation signal except: a. Engine overspeed; and b. Generator differential current.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.14	-------------------NOTES------------------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not normally be performed in MODE 1 or 2 unless the other two DGs are OPERABLE. If either of the other two DGs becomes inoperable, this Surveillance shall be suspended. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. 3. If grid conditions do not permit, the power factor limit is not required to be met. Under this condition, the power factor shall be maintained as close to the limit as practicable. 4. A single test of the common DG at the specified Frequency will satisfy the Surveillance for both units. --- Verify each required DG operating within the power factor limit operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 2860 kW; and b. For the remaining hours of the test loaded ≥ 2400 kW and ≤ 2600 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	-------------------NOTES------------------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 2400 kW and ≤ 2600 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. 3. A single test of the common DG at the specified Frequency will satisfy the Surveillance for both units. --- Verify each required DG starts and achieves: a. In ≤ 13 seconds, voltage ≥ 4010 V and frequency ≥ 58.8 Hz; and b. Steady state voltage ≥ 4010 V and ≤ 4310 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.16	-------------------NOTE-------------------- This Surveillance shall not normally be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --	
	Verify each required DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.17	-------------------NOTE-------------------- This Surveillance shall not normally be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify, with a required DG operating in test mode and connected to its bus: a. For Division 1 and 2 DGs, an actual or simulated ECCS initiation signal overrides the test mode by returning DG to ready-to-load operation; and b. For Division 3 DG, an actual or simulated DG overcurrent trip signal automatically disconnects the offsite power source while the DG continues to supply normal loads.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.18	-------------------NOTE-------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify interval between each sequenced load block, for Division 1 and 2 DGs only, is $\geq$ 90% of the design interval for each time delay relay.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2 only; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 13 seconds, 2. energizes auto-connected emergency loads including through time delay relays, where applicable, 3. maintains steady state voltage ≥ 4010 V and ≤ 4310 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.20	-------------------NOTE-------------------- All DG starts may be preceded by an engine prelube period. -- Verify, when started simultaneously from standby condition, each required DG achieves, in ≤ 13 seconds, voltage ≥ 4010 V and frequency ≥ 58.8 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.21	-------------------NOTE-------------------- When the opposite unit is in MODE 4 or 5, or moving irradiated fuel assemblies in secondary containment, the following opposite unit SRs are not required to be performed: SR 3.8.1.3, SR 3.8.1.9 through SR 3.8.1.11, SR 3.8.1.14 through SR 3.8.1.16. -- For required opposite unit DG, the SRs of the opposite unit's Specification 3.8.1, except SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.17, SR 3.8.1.18, SR 3.8.1.19, and SR 3.8.1.20, are applicable.	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources—Operating

LCO 3.8.4 The Division 1 125 VDC and 250 VDC, Division 2 125 VDC, Division 3 125 VDC, and the opposite unit Division 2 125 VDC electrical power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required Division 1, 2, or 3 125 VDC battery charger on one division inoperable. OR One required Division 2 or opposite unit Division 2 battery charger on one division inoperable. OR One required Division 1 250 VDC battery charger 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 ≤ 2 amps.	Once per 12 hours
	AND	
	A.3 Restore required battery charger(s) to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Division 1 or 2 125 VDC electrical power subsystem inoperable for reasons other than Condition A.	B.1 Restore Division 1 and 2 125 VDC electrical power subsystems to OPERABLE status.	2 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. Required Action and associated Completion Time of Condition A not met for the Division 3 DC electrical power subsystem. <u>OR</u> Division 3 DC electrical power subsystem inoperable for reasons other than Condition A.	C.1 Declare High Pressure Core Spray System inoperable.	Immediately
D. Required Action and associated Completion Time of Condition A not met for the Division 1 250 VDC electrical power subsystem. <u>OR</u> Division 1 250 VDC electrical power subsystem inoperable for reasons other than Condition A.	D.1 Declare associated supported features inoperable.	Immediately

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Required Action and associated Completion Time of Condition A not met for the opposite unit Division 2 DC electrical power subsystem. OR Opposite unit Division 2 DC electrical power subsystem inoperable for reasons other than Condition A.	E.1	Restore opposite unit Division 2 DC electrical power subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
F. Required Action and associated Completion Time of Condition A not met for the Division 1 or 2 125 VDC electrical power subsystem. OR Required Action and associated Completion Time of Condition E not met.	F.1 AND F.2	Be in MODE 3. Be in MODE 4.	12 hours 36 hours
G. Required Action and associated Completion Time of Condition B not met.	G.1	Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

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

1. SR 3.8.4.1 through SR 3.8.4.3 are applicable only to the given unit's DC electrical power sources.

2. SR 3.8.4.4 is applicable only to the opposite unit DC electrical power source.

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is greater than or equal to the minimum established float voltage.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.2	Verify each required battery charger supplies: a. ≥ 200 amps at greater than or equal to the minimum established float voltage for ≥ 4 hours for the Division 1 and 2 125 V battery chargers; b. ≥ 50 amps at greater than or equal to the minimum established float voltage for ≥ 4 hours for the Division 3 125 V battery charger; and c. ≥ 200 amps at greater than or equal to the minimum established float voltage for ≥ 4 hours for the 250 V battery charger. <u>OR</u> Verify each battery charger can recharge the battery to the fully charged state within 24 hours while supplying the largest combined demands of the various continuous steady state loads, after a battery discharge to the bounding design basis event discharge state.	In accordance with the Surveillance Frequency Control Program

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems—Operating

LCO 3.8.7 The following electrical power distribution subsystems shall be OPERABLE:

a. Division 1 and Division 2 AC and 125 V DC distribution subsystems;

b. Division 3 AC and 125 V DC distribution subsystems;

c. Division 1 250 V DC distribution subsystem; and

d. The portions of the opposite unit's Division 2 AC and 125 V DC electrical power distribution subsystems capable of supporting the equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," LCO 3.7.4, "Control Room Area Filtration (CRAF) System," LCO 3.7.5, "Control Room Area Ventilation Air Conditioning (AC) System," and LCO 3.8.1, "AC Sources-Operating."

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or both Division 1 and 2 125 V DC electrical power distribution subsystems inoperable.	B.1 Restore Division 1 and 2 125 V DC electrical power distribution subsystem(s) to OPERABLE status.	2 hours OR -----NOTE----- Not applicable when a loss of function occurs. --------------- In accordance with the Risk Informed Completion Time Program
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3.	12 hours
D. One or more required opposite unit Division 2 AC or DC electrical power distribution subsystems inoperable.	-------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.1 when Condition C results in the inoperability of a required offsite circuit. ----------------------------- D.1 Restore required opposite unit Division 2 AC and DC electrical power distribution subsystem(s).	 7 days OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Required Action and associated Completion Time of Condition D not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours
F. One or both Division 3 AC or DC electrical power distribution subsystems inoperable.	F.1 Declare associated supported features inoperable.	Immediately
G. Division 1 250 V DC electrical power subsystem inoperable.	G.1 Declare associated supported features inoperable.	Immediately
H. Two or more electrical power distribution subsystems inoperable that, in combination, result in a loss of function.	H.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.8.7.1 Verify correct breaker alignments and voltage to required AC and DC electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program

5.5 Programs and Manuals

5.5.16 Surveillance Frequency Control Program (continued)

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.

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 MODES 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 change, 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 limist 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 conditions 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:

(continued)

5.5 Programs and Manuals

5.5.18 Risk Informed Completion Time Program (continued)

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 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.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO

AMENDMENT NO. 251 TO RENEWED FACILITY OPERATING LICENSE NO. NPF-11

AND

AMENDMENT NO. 237 TO RENEWED FACILITY OPERATING LICENSE NO. NPF-18

EXELON GENERATION COMPANY, LLC

LASALLE COUNTY STATION, UNITS 1 AND 2

DOCKET NOS. 50-373 AND 50-374

1.0 INTRODUCTION

By application dated January 31, 2020 (Reference 1), as supplemented by letters dated October 1, 2020 (Reference 2) October 29, 2020 (Reference 3), March 31, 2021 (Reference 4), and May 10, 2021 (Reference 5), Exelon Generation Company, LLC (Exelon, the licensee) submitted a license amendment request (LAR) for LaSalle County Station, Units 1 and 2 (LaSalle).

The amendments would revise technical specification (TS) requirements to permit the use of risk-informed completion times (RICTs) for actions to be taken when limiting conditions for operation (LCOs) are not met. The proposed changes are based on Technical Specifications Task Force (TSTF) Traveler TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b," dated July 2, 2018 (Reference 6). The U.S. Nuclear Regulatory Commission (NRC or the Commission) issued a final model safety evaluation (SE) approving TSTF-505, Revision 2, on November 21, 2018 (Reference 7).

The licensee has proposed variations from the TS changes described in TSTF-505, Revision 2, which are described in Section 2.2.4 of this SE.

The NRC staff participated in a regulatory audit in June 2020, to ascertain the information needed to support its review of the application and to develop requests for additional information (RAIs), as needed. On September 21, 2020, the NRC staff issued an audit summary (Reference 8). By electronic mail communications dated September 3, 2020 (Reference 9), September 16, 2020 (Reference 10), September 29, 2020 (Reference 11), and March 1, 2021 (Reference 12), the NRC staff sent RAIs to the licensee. By letters dated October 1, 2020, October 29, 2020, March 31, 2021, and May 10, 2021, the licensee responded to the RAIs. The supplemental letters provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the NRC staff's original

proposed no significant hazards consideration determination as published in the *Federal Register* on April 7, 2020 (85 FR 19511).

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 Time(s) (CT). The CTs are referred to as the "front stops" in the context of this SE. For certain conditions, the TS require exiting the Mode of Applicability of an LCO (i.e., shut down the reactor).

2.2 Description of TS Changes

The licensee's 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 Nuclear Energy Institute (NEI) Topical Report (TR) 06-09-A, "Risk-Informed Technical Specifications Initiative 4b: Risk-Managed Technical Specification (RMTS)," October 2012 (Reference 13). NEI 06-09-A dated October 2012 provides a methodology for extending existing CTs and, thereby, delay exiting the operational mode of applicability or taking "Required Actions" if risk is assessed and managed within the limits and programmatic requirements established by a RICT program. NEI 06-09-A incorporates NRC staff final model SE approving the NEI 06-09, dated May 17, 2007. The NRC staff issued Revision 2 to the final model SE approving NEI 06-09-A (Reference 14). The licensee's application for the changes proposed to use NEI 06-09-A and included documentation regarding the technical acceptability of the probabilistic risk assessment (PRA) models for the RICT program, consistent with the guidance of Regulatory Guide (RG) 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities" March 2009 (Reference 15).

2.2.1 TS 1.0 - Use and Application

Example 1.3-8, will be added to TS 1.3, CTs, and will read as follows:

EXAMPLE 1.3-8

ACTIONS

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

When a subsystem is declared inoperable, Condition A is entered. The 7 day Completion Time May be applied as discussed in Example 1.3-8. However, the licensee May elect to apply the Risk Informed Completion Time Program which permits calculation of a Risk Informed Completion Time (RICT) that May be used to complete the Required Action beyond the 7 day Completion Time. The RICT cannot exceed 30 days. After the 7 day Completion Time has expired, the subsystem must be restored to OPERABLE status within the RICT or Condition B must also be entered.

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

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

If the RICT expires or is recalculated to be less than the elapsed time since the Condition was entered and the inoperable

subsystem has not been restored to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable subsystems are restored to OPERABLE status after Condition B is entered, Conditions A and B are exited, and therefore, the required actions of Condition B May be terminated.

2.2.2 TS 5.5.17 - Risk-Informed Completion Time Program

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

Risk Informed Completion Time Program

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

a. The RICT May not exceed 30 days;

b. A RICT May only be utilized in MODES 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 [probabilistic risk analysis] shall be based on 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 reviewed the licensee's proposed addition of the RICT program to the Administrative Controls Section of the TS. The NRC staff evaluated the elements of the new program to ensure alignment with the requirements in Title 10 of the *Code of Federal Regulations* (10 CFR) 50.36(c)(5) and to ensure the programmatic controls are consistent with the RICT program described in NEI 06-09-A.

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

2.2.3 Application of the RICT program to existing LCOs and Action statements

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

ACTIONS

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

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

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

- TS 3.1.7 - Standby Liquid Control (SLC) System
  Action A.1

- TS 3.3.1.1 - Reactor Protection System (RPS) Instrumentation
  Action A.1
  Action A.2
  Action B.1
  Action B.2

- TS 3.3.2.2 - Feedwater System and Main Turbine High Water Level Trip Instrumentation
  Action A.1

- TS 3.3.5.1 - Emergency Core Cooling System (ECCS) Instrumentation
  Action B.3
  Note *Not applicable when a loss of function occurs.*
  Action C.2
  Note *Not applicable when a loss of function occurs.*
  Action E.2
  Note The Risk Informed Completion Time Program is not applicable when a loss of function occurs.
  Action F.2
  Note *The Risk Informed Completion Time Program is not applicable when a* loss of function occurs.

- TS 3.3.5.3 - Reactor Core Isolation Cooling (RCIC) System Instrumentation
  Action B.2
  Note *Not applicable when a loss of function occurs.*
  Action D.2.1
  Note *Not applicable when loss of function occurs.*

- TS 3.3.6.1 - Primary Containment Isolation Instrumentation
  Action A.1

- TS 3.3.8.1 - Loss of Power (LOP) Instrumentation
  Action A.1
  Note *Not applicable when a loss of function occurs.*

- TS 3.6.1.2 - Primary Containment Air Locks
  Action C.3

- TS 3.6.1.3 - Primary Containment Isolation Valves (PCIVs)
  Action A.1
  Action A.2
  Action C.2

- TS 3.6.1.6 - Suppression Chamber-to-Drywell Vacuum Breakers
  Action A.1

- TS 3.6.2.3 - Residual Heat Removal (RHR) Suppression Pool Cooling
  Action A.1

- TS 3.6.2.4 - Residual Heat Removal (RHR) Suppression Pool Spray
  Action A.1

- TS 3.7.1 - Residual Heat Removal Service Water (RHRSW) System
  Action A.1

- TS 3.8.1 - AC (Alternating Current) Sources – Operating
  Action A.3
  Action B.4
  Action D.2
  Action E.1
  Action E.2

- TS 3.8.4 - DC (Direct Current) Sources – Operating
  Action A.3
  Action B.1

- TS 3.8.7 - Distribution Systems – Operating
  Action A.1
  Note *Not applicable when loss of function can occur.*
  Action B.1
  Note *Not applicable when loss of function can occur.*

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

2.2.4.1 Scope of LCOs included in RICT Program

The following LaSalle LCOs have been proposed to be included within the scope of the RICT program; however, they are not included in the generic list of LCOs approved by the NRC in TSTF-505.

- TS 3.3.4.2 - Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation
  Action A.1
  Action A.2

- TS 3.5.1 - ECCS – Operating
  Action A.1
  Action B.2
  Action C.1
  Action E.1

- TS 3.5.3 - RCIC System Action A.2

2.2.4.2 Scope of TS REQUIRED ACTIONS included in RICT Program

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

- TS 3.3.5.1 - Emergency Core Cooling System (ECCS) Instrumentation
  Action D.3
  Note *Not applicable when a loss of function occurs.*
  Action D.4
  Note *Not applicable when a loss of function occurs.*

- TS 3.8.1 - AC Sources – Operating
  Action C.4
  Note *Not applicable when a loss of function occurs.*

- TS 3.8.4 - DC Sources – Operating
  Action E.1

- TS 3.8.7 - Distribution Systems – Operating
  Action D.1

2.3 Regulatory Review

2.3.1 Applicable Regulations

The regulation at 10 CFR Section 50.90, "Application for amendment of license, construction permit, or early site permit," states 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" states 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, "Criteria for Protection Systems for Nuclear Power Generating Stations," or the requirements in IEEE Std 603-1991, "Criteria for Safety Systems for Nuclear Power Generating Stations," and the correction sheet dated January 30, 1995. The LaSalle construction permits were issued on September 10, 1973, so that this requirement is applicable to LaSalle.

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

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

2.3.2 Regulatory Guidance (RG)

The NRC staff considered the following RG 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 2, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis" (Reference 16).

- RG 1.177, Revision 1, "An Approach for Plant-Specific, Risk-Informed Decision-making: Technical Specifications" (Reference 17).

- NUREG-1855, Revision 1, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decisionmaking" (Reference 18).

- NUREG-0800, "Standard Review Plan [SRP] for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [light-water reactor] Edition," Chapter 19, Section 19.2, "Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance" (Reference 19) and Section 16.1, "Risk-Informed Decision Making: Technical Specifications" (Reference 20).

The licensee's submittal cites Revision 2 of RG 1.200 and RG 1.174, and Revision 1 of RG 1.177, respectively. The RGs have been updated since the time of the licensee's submittal. The updates do not include any technical changes that would impact the plants' consistency with NEI 06-09-A, therefore, the NRC staff finds Revision 2 of RG

1.200 and RG 1.174, and Revisions 1 and 2 of RG 1.177, acceptable for the implementation of the RICT program.

NRC Endorsed Guidance

NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines" provides guidance for risk-informed TS. The NRC staff issued a final model SE approving NEI 06-09 on May 17, 2007.

3.0 TECHNICAL EVALUATION

3.1 Method of Staff Review

The NRC staff reviewed the licensee's PRA peer review history and results, alternative methods and proposed approaches to determine if they are technically acceptable for use in the proposed risk-informed completion time 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 provided in Section C of RG 1.174, Revision 2, and the three-tiered approach outlined in Section C of RG 1.177, Revision 1. 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 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 principles and tiers are addressed in NEI 06-09, Revision 0-A. NEI 06-09-A provides a methodology for extending existing CTs, 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 RICTs against the key safety principles is discussed below.

3.2 Review of Key Principles

RG 1.177, Revision 1, and RG 1.174, Revision 2, identify five key principles to be applied to risk-informed changes to the TSs. Each of these principles is addressed in NEI 06-09-A. The NRC staff's evaluation of the licensee's proposed use of RICTs against these key principles is discussed below.

3.2.1 Key Principle 1: Evaluation of Compliance with Current Regulations

Paragraph 50.36(c)(2) of 10 CFR requires 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 TS 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 shutdown or Required Actions, if risk is assessed and managed appropriately within specified limits and programmatic requirements and the safety margins and DID remains sufficient. The option to determine the extended CT in accordance with the RICT program allows the licensee to perform an integrated evaluation in accordance with the methodology prescribed in NEI 06-09, Revision 0-A and TS 5.5.17. The RICT is limited to a maximum of 30 days (termed the "back stop").

With the incorporation of the RICT program, the required performance levels of equipment specified in LCOs are not changed, only the required CT for the Required Actions are modified, such that 10 CFR 50.36(c)(2) will remain met. Based on the discussion provided above, the NRC staff finds that the proposed changes meet the first key principle of RG 1.174, Revision 2, and RG 1.177, Revision 1.

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

In RG 1.174, Revision 2, the NRC identified the following considerations used for evaluation of 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 licensee is proposing no changes to the design of the plant or any operating parameter, and no new changes to the design basis in the proposed changes to the TS.

The effect of the proposed changes when implemented will allow CTs to vary, based on the risk significance of the given plant configuration (i.e., the equipment out-of-service at any given time), provided that the system(s) retain(s) the capability to perform the applicable safety function(s) without any further failures (e.g., one train of a two -train system is inoperable).

These restrictions on inoperability of all required trains of a system ensure that consistency with the DID philosophy is maintained by following existing guidance when the capability to perform TS safety function(s) is lost.

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

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

The licensee has requested to use the RICT program to extend the existing CTs for the respective TS LCOs listed in Section 2.2 of this SE. The NRC staff's evaluation of the proposed changes for these LCOs assessed the plant-specific redundant or diverse means to mitigate accidents to ensure consistency with the plant LB requirements.

Attachment 7, "Evaluation of Instrumentation and Control Systems," of the LAR provided information supporting the evaluation of the redundancy, diversity, and DID of instrumentation included in the proposed TS changes. The I&C TS LCOs with risk informed completion times for certain required actions include:

LCO 3.3.1.1	Reactor Protection System (RPS) Instrumentation
LCO 3.3.2.2	Feedwater System and Main Turbine High Water Level Trip Instrumentation
LCO 3.3.4.2	Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation
LCO 3.3.5.1	ECCS Instrumentation
LCO 3.3.5.3	Reactor Core Isolation Cooling (RCIC) System Instrumentation
LCO 3.3.6.1	Primary Containment Isolation Instrumentation
LCO 3.3.8.1	Loss of Power (LOP) Instrumentation

The NRC staff evaluated Attachment 7 of the LAR using the guidance prescribed in RG 1.174, RG 1.177, and TSTF-505, to ensure adequate DID (for each of the functions) to operate the facility in the proposed manner (i.e., that the changes are consistent with the DID criteria). The applicable defense-in-depth criteria for the affected LaSalle I&C systems include: (1) over-reliance on programmatic activities, as compensatory measures associated with the change in the licensing basis, is avoided; (2) 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); (3) defenses against potential CCF are maintained and the potential for the introduction of new common cause failure mechanisms is assessed; and (4) the intent of the plant's design criteria is maintained.

The NRC staff reviewed the specific trip logic arrangements, redundancy, backup systems, manual actions, and diverse trips specified for each of the protective safety functions and associated instrumentation as described in associated Updated Final Safety Analysis Report (UFSAR), (Reference 21)Chapter 7 sections, and as reflected in Attachment 7 of the LAR for each I&C LCO above.

In response to EEOB RAI No. 3, the licensee submitted a letter, RS-20-123, dated October 1, 2020, and provided a table that demonstrates conditions which do and do not reflect a loss of function (LOF) for the LOP instrumentation, based on the listed combinations of inoperable channels. The NRC staff reviewed the trip logic arrangement, redundancy, and diverse input trips for the LOP instrumentation as shown in UFSAR Section 8.2.3.3, and as reflected in Attachment 7 of the LAR, and found the response acceptable. Under certain circumstances, when trip capability may not be maintained, a Note was added to the CT which prohibits applying a RICT when trip capability is not maintained.

The licensee confirmed, and NRC staff verified, that in accordance with the LaSalle UFSAR and equipment and actions credited in Attachment 7 of the LAR, 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. Therefore, NRC staff concludes that the intent of the plant's design criteria (e.g., safety functions) applicable to the proposed I&C LCOs provided in Section 2.2 of this SE are maintained.

The NRC staff notes 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 LaSalle UFSAR and the risk informed LCO conditions for the affected safety functions. Based on this information, the NRC staff confirmed that under any given design-basis accident (DBA) evaluated in the LaSalle UFSAR, the affected protective features maintain adequate DID.

In conclusion, the NRC staff agrees that there is sufficient redundancy, diversity, and DID, to protect against CCFs and potential single failure for the LaSalle instrumentation systems evaluated in LAR Attachment 7 during a RICT. There is at least one diverse means specified by the licensee for initiating mitigating action for each accident event, thus providing DID against a failure of instrumentation during the RICT for each LCO. The DID specified by the licensee does not overly rely on manual actions as the diverse means; therefore, there is no over-reliance of programmatic activities as compensatory measures.

According to UFSAR Sections 8.2.3.2, 8.3.1.4.1, and 8.3.2.1.1, the electrical power system consisting of both AC and DC portions is designed to perform its safety functions assuming a single failure. The single failure criterion is preserved by specifying that all redundant components of safety-related systems are required to be operable when a plant enters an LCO (i.e., in an ACTION statement). In the evaluation below, the staff considers the LaSalle plant configurations from a DID perspective.

UFSAR Section 8.2.1.2, "Power Sources," states that the primary offsite power source for each LaSalle unit consists of a separate power feeder from the 345 kilovolt (kV) switchyard. That feeder connects to a system auxiliary transformer (SAT) and provides power to the unit's 4.16 kV and 6.9 kV auxiliary power systems. Tie breakers in the onsite ac system allow each SAT to be the other unit's second offsite ac power source, in conformance with General Design Criterion (GDC) 17 – "Electrical Power Systems" discussed in UFSAR Section 3.1.2.2.8. For normal plant operation, each unit's auxiliary loads are supplied from its main generator (MG) through the unit's auxiliary power transformer (UAT). If necessary, a third offsite AC power source, not credited per GDC 17, can be provided to a unit by back feeding through its main power transformer and UAT after isolating the MG.
UFSAR Section 8.1.2.2, "Unit Class 1E A-C Power System," states that each unit's 4.16 kV AC power system is divided into three emergency safety features (ESF) independent divisions 1, 2, and 3. Each division's 4.16 kV bus can be connected to offsite AC sources or its dedicated

diesel generator (DG) except for Division 1 which has the common DG 0 for both units' Division 1 buses. A Division 3 DG for each unit is dedicated to the high-pressure core spray (HPCS) system only and cannot provide AC power to the Division 1 or Division 2 ESF loads. Divisions 1 and 2 DGs provide power to safe shutdown loads with either division able to safely shut down its assigned unit for non-accident conditions. UFSAR Section 8.3.1.2, "Analysis," states, "The standby DGs supply plant buses so that the loss of any one of the DGs will not prevent the safe shutdown of either unit. The total system satisfies single-failure criteria."

UFSAR Table 8.3-1, "Loading on 4160-Volt Buses," provides a listing of electrical loads required to mitigate the consequences of a loss-of-coolant accident (LOCA) in Unit 1 coincident with a loss of offsite power (LOOP) condition for the station and controlled safe shut down of both units. The table depicts that the accident unit (Unit 1) has Divisions 1, 2, and 3 AC and DC power sources. The non-accident unit (Unit 2) requires ESF Division 2 AC and DC power sources.

UFSAR Section 8.3.2.1.1, "Unit Class 1E D-C Power System," states that the Class 1E DC power system for each unit consists of three 125-Vdc (volts direct current) (Divisions 1, 2, and 3) and one Division 1 250-Vdc battery systems. Each 125-Vdc system is sized to supply control power for its divisional switchgear, relays, solenoid valves, and instruments. Divisions 1 and 2 batteries are sized to start and carry the normal and safe shutdown loads for 4 hours following loss of all AC power. The single 250-Vdc battery supplies power to the main turbine loads and serves as backup feed to the plant computer and RCIC system. Each DC system has its own battery, battery charger, and distribution bus, with the Divisions 1 and 2 125 Vdc systems having two redundant battery chargers. If the battery chargers are out of service, the associated DC system loads for that Division are supplied by its battery.

UFSAR Section 8.3.1.1.4, "Instrument Power System," states that the 120-Vac power vital systems are designed to supply continuous power to the instrument systems which must remain in operation during a loss of input AC power. Load centers for the 120-Vac systems serving ESF Class 1E instrumentation and indication loads and other essential loads are fed from Class 1E power system motor control centers (MCCs).

The licensee requested a change to the LaSalle LB to use the RICT program to extend the CTs for ACTION statements in TS 3.8, "Electrical Power Systems," Actions. The NRC staff's evaluation of the proposed changes considered potential plant conditions for the proposed RICTs, and the availability of AC and DC power sources for mitigating the consequences of an accident in one unit and controlled safe shutdown of the other unit.

The NRC staff reviewed the TS Conditions in the application, the UFSAR, and applicable TS LCOs, 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 (DSC) listed in LAR Table E1-1 of LAR Enclosure 1, "In Scope TS/LCO conditions to Corresponding PRA Functions," reflects the minimum electrical power sources/subsystems required to be operable by the LCOs to support the safety functions necessary to mitigate postulated DBAs, safely shut down the reactor, and maintain it in that 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 non-safety related) that are available at LaSalle and capable of performing the same safety function of the inoperable electrical power source/equipment. In addition, the NRC staff reviewed the proposed

risk management action (RMA) examples for reasonable assurance that these RMAs are appropriate to monitor and control risk for applicable TS conditions. The staff's evaluation of these matters is provided below.

TS 3.8.1, Condition A

The licensee proposed to use the RICT program to extend the existing 72-hour CT for Required Action (RA) A.3 to restore the required one offsite circuit to operable status for TS 3.8.1, "AC Sources – Operating," Condition A. The example calculation in Table E1-2, "Example RICT Calculations," indicates a RICT of 30 days. The safety function covered by the corresponding TS LCO is the GDC 17-related offsite power requirement for safe shut down of both reactors. The NRC staff found that the generic and specific RMAs for TS 3.8.1.1 RA A.3. are reasonable, and they are consistent with the intent of NEI 06-09-A, Section 3.4.3, for risk awareness and control during the emergent scenarios for TS 3.8.1, Condition A.

According to LAR Table E1-1, the DSC for TS 3.8.1, Condition A, is "one offsite source." For Condition A both units would enter the LCO and each unit would still have one of the two offsite sources available to it. The available offsite circuit and the associated SAT have adequate capacity for safe shut down of both units for a DBA in one unit and controlled shutdown of the other unit. As a DID measure, the DGs are available to support safe shut down of both units.

Based on the above discussion, the NRC staff finds that during the RICT program entry for TS 3.8.1, Condition A, the DID of the electrical power systems that ensures AC power to key safety-related equipment required to operate during DBAs is reduced to at least the required minimum electrical power source. Based on the availability of the electrical power equipment to support the safety functions, the NRC staff finds the proposed change to TS 3.8.1, Condition A, acceptable.

TS 3.8.1, Condition B

The licensee proposed to use the RICT program to extend the existing 14-day CT for RA B.4 to restore the required DG to operable status for TS 3.8.1, Condition B. The example calculation in LAR Enclosure 1, Table E1-2, indicates a RICT of 30 days. The safety function covered by TS LCO 3.8.1 is the operability of AC sources required for safe shutdown of the reactor and maintaining it in safe condition.

The LAR does not provide DSC for the non-accident unit or the ability to safely shut down the unit using installed plant equipment. The NRC staff analyzed the safe shutdown capability of the non-accident unit for (1) offsite power available, (2) a station LOOP, and (3) a station LOOP concurrent with a LOCA in Unit 1, as described below. The NRC staff found that the generic and specific RMAs for TS 3.8.1 Condition B, are reasonable and consistent with the intent of NEI 06-09-A Section 3.4.3 for risk awareness and control during the emergent scenarios for TS 3.8.1, Condition B.

The NRC staff evaluated TS 3.8.1, Condition B, in which one required DG (either Division 1 or Division 2) of a unit or the Division 2 DG of the opposite unit is in Condition B and thus inoperable, with both units entering the LCO for the following postulated conditions.

1. With offsite power available

   1a. During the RICT program entry for TS 3.8.1, Condition B, with either the Division 1 or Division 2 DG inoperable, the AC power required to support LCO 3.8.1 safety

function is provided by primarily the affected unit's offsite sources or if necessary by the available DG for that unit from either the Division 1 (DG 0) or Division 2 DG if offsite power is lost or an accident occurs. Therefore, while the redundancy of the AC power sources is reduced, the LCO 3.8.1 safety function is maintained.

1b. During the RICT program entry for TS 3.8.1, Condition B, with the Division 2 DG of the opposite unit inoperable and with both units in this TS condition, the AC power required to support LCO 3.8.1 safety function is provided by primarily the affected unit's offsite sources or, if necessary, by DG 0 if offsite power is lost or an accident occurs. Therefore, while the redundancy of the AC power sources is reduced, the LCO 3.8.1 safety function is maintained.

2. <u>Loss of offsite power</u>

2a. Assuming a station LOOP, during the RICT program entry for TS 3.8.1, Condition B, with either the Division 1 or Division 2 DG inoperable, the AC power required to support the LCO 3.8.1 safety function is provided by the affected unit's available DG either from Division 1 or Division 2 as indicated above for 1a. Therefore, while the redundancy of the AC power sources is reduced, the LCO 3.8.1 safety function is maintained.

2b. Assuming a station LOOP, during the RICT program entry for TS 3.8.1, Condition B, with the Division 2 DG of the opposite unit inoperable and with both units in this TS condition, the AC power required to support the LCO 3.8.1 safety function is provided by the Division 1 DG (DG 0). Therefore, while the redundancy of the AC power sources is reduced, the LCO 3.8.1 safety function is maintained.

3. <u>LOOP and LOCA</u>

The licensing basis for LaSalle, as described in the UFSAR, is a LOOP for the station, an accident in one unit, and controlled shutdown of the opposite unit. UFSAR Table 8.3-1 provides a listing of loads available to be supplied by the DGs and identifies the minimum requirements under these conditions. The LaSalle accident analyses credit the loading of the DGs based on the occurrence of a LOOP coincident with a LOCA. UFSAR, Section 6.3.3.3, "Single Failure Considerations," states that Table 6.3-6 shows that all potential single failures can be identified as no more severe than one of the following failures: (1) the Division 1, 2, or 3, DGs for a unit or (2) one automatic depressurization system valve. In addition, for large breaks, the failure of any DG is generally the most severe failure, while for small breaks, the most severe failure is the failure of the HPCS due to failure of its associated DG. For this LAR, the RICT program entry for the TS 3.8.1.B conditions described below were evaluated based on the assumption that a station LOOP occurs concurrent with a LOCA in Unit 1.

3a. RICT Program entry for an Inoperable Division 1 DG (DG 0)

Under this plant configuration, the Unit 1 Division 2 DG is available to supply the Unit 1 safe-shutdown loads while the Unit 1 Division 3 DG addresses reactor vessel inventory during LOCA, and the Unit-2 Division 2 DG has adequate capacity to support its unit's controlled shutdown.. Therefore, while the redundancy of the AC power sources is reduced, the LCO 3.8.1 safety function is maintained.

3b. RICT Program entry for an Inoperable Division 2 DG of either unit

The Unit 1, Division 2 DG is assumed to be inoperable in scenario 3b.i. below, and the Unit 2, Division 2 DG is assumed inoperable in scenario 3.b.ii. below, with each scenario bring independent of the other. In the RAI response dated May 10, 2021, the licensee addressed those two scenarios as follows:

i) For an inoperable Unit 1 Division 2 DG in the RICT program, DG 0 (the Division 1 DG), and the Unit 1 Division 3 DG, will be available to mitigate the consequences of the accident, and the Division 2 DG would be available to support safe shutdown of Unit 2. This is a similar scenario as outlined above for an inoperable Division 1 (DG 0) (i.e., scenario 3a), in that each unit has a DG available for its controlled shutdown, while the Division 3 HPCS DG is only required for reactor vessel inventory in the accident unit.

ii) For an inoperable Unit 2 Division 2 DG in the RICT program, the DG 0, Unit 1 Division 2 DG, and Unit 1 Division 3 DGs are available to mitigate the consequences of the accident in Unit 1. The unavailability of a single Unit 2 Division 2 DG (in the RICT program) would necessitate implementation of Station Blackout (SBO) contingency actions in Unit 2 to achieve safe shutdown. Operator actions are required to repower the non-accident unit (Unit 2) Division 1 bus from the accident unit (Unit 1) when conditions have stabilized. In the March 31, 2021, RAI response, the licensee stated that, for the accident condition in Unit 1, Emergency Operating Procedure (EOP) – LOP-AP-101, "Unit 1, AC Power System Abnormal," would be used to support mitigation of the event, and EOP LOP-AP-201, "Unit 2, AC Power System Abnormal," would be used to support coping and recovery on Unit 2.

The NRC staff notes that supplying the non-accident unit's Division 1 bus from the accident unit's Division 1 bus (powered by DG 0), using the referenced EOPs, requires operator actions described in detail in the licensee's RAI response. Those operator actions include defeating the interlocks of the tie breakers connecting the two Division 1 buses to repower the non-accident unit's Division 1 bus in less than four hours, which is LaSalle Station's SBO coping duration. Once the Unit 2, Division 1 bus is repowered, a controlled shutdown of that unit is attainable as discussed in the licensee's March 31, 2021, RAI response

Based on the above discussion, the NRC staff finds that during the entry of the RICT program for TS 3.8.1.B with the Division 2 DG in either unit inoperable, the LCO 3.8.1 safety function is maintained.

3c. RICT Program entry for an inoperable opposite unit Division 2 DG

This plant configuration is similar to RICT program entry for Division 2 DG scenarios 3b.i and 3b.ii discussed above, depending on which is the accident/non-accident unit. Therefore, for the reasons described above with respect to scenarios 3b.i and 3b.ii, the NRC staff finds that during the entry of the RICT program for TS 3.8.1.B with the opposite unit Division 2 DG inoperable, the LCO 3.8.1 safety function is maintained.

The NRC staff notes that any postulated condition that results in three or more AC power sources being inoperable would require entry into TS 3.8.1, Condition I, which, in turn, requires

an immediate entry into LCO 3.0.3. Thus, use of the RICT program in this scenario is not applicable.

Based on the above discussion, the NRC staff finds that during the RICT program entry for TS 3.8.1, Condition B, when a LOF has not occurred, the DID of the electrical power systems that ensures AC power to key safety-related equipment required to operate during and following DBAs, with or without offsite power, is reduced to at least the required minimum AC power source. While the redundancy of the AC power sources is reduced, the LCO 3.8.1 safety function is maintained. Therefore, the NRC staff finds the proposed change to TS 3.8.1, Condition B, acceptable.

TS 3.8.1, Condition C

The licensee proposed the option to use the RICT program to extend the existing 72-hour CT for RA C.4 to restore the required DG(s) to operable status for TS 3.8.1, Condition C. The example calculation in LAR Table E1-2, "Example RICT Calculations," indicates a RICT of 30 days. The safety function covered by TS 3.8 LCO is the GDC 17-related power requirement for safe shutdown of both reactors. According to Table E1-1, the DSC for TS 3.8.1, Condition C, references TSs 3.8.1.A and 3.8.1.B. TS 3.8.1.A credits "one offsite source" and TS 3.8.1.B requires "one diesel per required division" as modified by the May 10, 2021, RAI response. The NRC staff found that the generic RMAs applicable to TS 3.8.1. RA C.4 are reasonable, and are consistent with the intent of NEI 06-09-A, Section 3.4.3, for risk awareness and control during the emergent scenarios for TS 3.8.1, Condition C.

The NRC staff evaluated the loss of each DG and the consequences on dual unit operation when Condition C, related to a loss of one required Division 3, OR one required Division 1, 2, or 3, DG and opposite unit Division 2 DG results in both units entering the LCO.

(1) Loss of Required Division 3 DG in Either Unit

    Each LaSalle unit has one Division 3 DG dedicated to the HPCS pump. The safety function covered by TS 3.8.1 Condition C is the GDC 17-related power requirement for safe shutdown of both reactors. For an accident in Unit 1, with Unit 1 Division 3 DG in a RICT, DG 0 and the Division 2 DG are available to mitigate the consequences of the accident and Unit 2 Division 2 DG is available for controlled safe shutdown of Unit 2.

(2) Loss of one required Division 1, 2, or 3, DG and Required opposite unit Division 2 DG inoperable.

    Based on the above discussion, the NRC staff finds that during the RICT program entry for TS 3.8.1, Condition C, when not precluded by a LOF, the DID of the electrical power systems that ensures onsite AC power to key safety-related equipment required to operate during DBAs, with or without offsite power, is reduced to at least the required minimum electrical power source. Based on the availability of the onsite electrical power equipment to support the safety functions, the NRC staff finds the proposed change to TS 3.8.1, Condition C, acceptable.

TS 3.8.1, Condition D

The licensee proposed the option to use the RICT program to extend the existing 24-hour CT for RA D.2 to restore one required offsite source to operable status for TS 3.8.1, Condition D. The example calculation in LAR Table E1-2 indicates a RICT of 30 days. The safety function

covered by this TS LCO is the GDC 17-related power requirement for safe shutdown of both reactors. According to LAR Table E1-1, the DSC for TS 3.8.1, Condition D, references TSs 3.8.1.A and 3.8.1.B. TS 3.8.1.A credits “one offsite source” and also TS 3.8.1.B requires “one diesel per required division” per the May 10, 2021, RAI response. Example RMAs for TS 3.8.1, Condition D, are provided in Enclosure 12 of the LAR for TS 3.8.1, Condition A. The NRC staff found that the generic and specific RMAs for TS 3.8.1, Condition D, are reasonable and consistent with the intent of NEI 06-09-A, Section 3.4.3, for risk awareness and control during the emergent scenarios.

The NRC staff evaluated the loss of both offsite sources and the consequences on dual unit operation for TS 3.8.1, Condition D. For loss of both offsite sources, there is decrease in redundancy and DID; however, the onsite power system, consisting of three DG sets shared between AC power systems for both units and one dedicated HPCS DG for each unit will be capable of supplying power to ESF systems required to mitigate an accident in Unit 1 and controlled shutdown of the non-accident unit.

Based on the above discussion, the NRC staff finds that during the RICT program entry for TS 3.8.1, Condition D, that even though AC power sources to ESF equipment are reduced the availability of other redundant AC sources allows the proposed change to TS 3.8.1, Condition D, acceptable.

<u>TS 3.8.1, Condition E</u>

The licensee proposed the option to use the RICT program to extend the existing 12-hour CT for RAs E.1 and E.2 to restore the required offsite source or required DG to operable status for TS 3.8.1, Condition E. The example calculation in LAR Table E1-2 indicates a RICT of 11.1 days. The safety function covered by this TS LCO is the GDC 17-related power requirement for safe shutdown of both reactors. According to Table E1-1, the DSC for TS 3.8.1, Condition E, references TSs 3.8.1.A and 3.8.1.B. TS 3.8.1.A credits “one offsite source” and TS 3.8.1.B requires “one diesel per required division” per the May 10, 2021, RAI response. Example RMAs for TSs 3.8.1, Conditions A and B, in LAR Enclosure 12 are applicable to TS 3.8.1, Condition E. The NRC staff found that the generic and specific RMAs for TS 3.8.1, Condition E, are reasonable and consistent with the intent of NEI 06-09-A, Section 3.4.3, for risk awareness and control during the emergent scenarios.

The proposed change to TS 3.8.1, Conditions B and C, discussed above consider the loss of each individual DG and the potential consequences on dual unit operation. The loss of any single DG was concluded to be acceptable assuming an accident in Unit 1 and a station LOOP. The proposed change to TS 3.8.1, Condition E, includes loss of an additional offsite power circuit. However, for TS 3.8.1, Condition B, discussed above, the licensee assumed that both offsite sources were unavailable due to a LOOP. Even though there is decreased redundancy due to the unavailability of one offsite source and one DG, if one offsite source is available, then both units can be safely shutdown using offsite power alone without any reliance on the onsite power system. The NRC staff notes that the unavailability of a Division 2 DG in the non-accident unit may require the licensee to initiate SBO contingency actions as detailed in the licensee’s March 31, 2021, RAI response in accordance with plant procedures.

Based on the above discussion, the NRC staff finds that during the RICT program entry for TS 3.8.1, Condition E, the DID of the electrical power systems that ensures AC power to key safety-related equipment required to operate during DBAs is reduced to at least the required minimum electrical power source. Based on the availability of the electrical power system to

support the safety functions, the NRC staff finds the proposed change to TS 3.8.1, Condition E, acceptable.

TS 3.8.4, Condition A

The licensee proposed the option to use the RICT program to increase the existing 7-day CT for RA A.3 to restore inoperable battery chargers to operable status for TS 3.8.4, “DC Sources Operating,” Condition A. The example calculation in LAR Table E1-2 indicates a RICT of 3 days. The safety function covered by this TS LCO is the GDC 17-related power requirement for safe shutdown of both reactors. TS 3.8.4 Condition A addresses a situation in which (1) one required Division 1, 2, or 3 125 VDC battery charger on one division is inoperable, or (2) one required Division 2 or the opposite unit Division 2 battery charger on one division is inoperable, or (3) one required Division 1 250 VDC battery charger is inoperable. According to LAR Table E1-1, the DSC for TS 3.8.4, Condition A, credits “one per required division.” The NRC staff found that the generic and specific RMAs for TS 3.8.4 RA A.3 are reasonable, and are consistent with the intent of NEI 06-09-A, Section 3.4.3, for risk awareness and control during the emergent scenarios for TS 3.8.4, Condition A.

The NRC staff evaluated the loss of each battery charger for TS 3.8.4, Condition A, and the consequences on dual unit operation.

(1) For the loss of a single Division 1 battery charger, the redundant charger is available in Division 1, but entry into the LCO is only made when one required charger is not available. The licensee stated in its March 31, 2021, RAI response that the backup Division 1 battery charger would supply the Division 1 DC loads for the unit since both battery chargers for Division 1 are not placed in maintenance concurrently. Considering a worst-case scenario where both Division 1 battery chargers were unavailable, with the further assumption that the Division 1 battery is fully discharged for that unit eventually due to loss of its chargers, the Division 2 and Division 3 battery chargers are still available to meet the DSC of “one per required division” stated in Table E1-1 of the LAR to support that unit’s safe shutdown as necessary. As has been stated previously, a unit only needs two ESF divisions to safely shutdown for an accident.

(2) For the unavailability of one Division 2 battery charger, the backup battery charger would be called into service as described for Division 1 above. For a worst-case scenario in which both required Division 2 battery chargers were unavailable, with a Division 2 battery fully discharged in the non-accident unit, concurrent with a dual unit LOOP and accident in one unit, the licensee may need to implement SBO contingency actions as described in the March 31, 2021, RAI response, in accordance with plant procedures.. Following these actions, the DSC of “one per required division” stated in Table E1-1 of the LAR would be met.

(3) For the loss of a Division 3 battery charger, the same logic applies as indicated above for the Division 1 and Division 2 battery chargers, resulting in loss of Division 3. However, this configuration would be acceptable because of the availability of the other two ESF divisions for each unit to meet the DSC of “one per required division” stated in Table E1-1 of the LAR.

(4) For the loss of a Division 1 250 Vdc battery charger for either unit, the important load that is lost is the RCIC pump in regard to safe shutdown. The 250 Vdc system does not supply any ESF Division or loads. For the scenario of an accident in one unit and station loop, the accident unit would have three ESF divisions available and the non-accident

unit would have two ESF divisions available. Hence the DSC of “one per required division” stated in Table E1-1 of the LAR is met and the safety function is maintained in both units.

Based on the above discussion, the NRC staff finds that during the RICT program entry for TS 3.8.4, Condition A, the DID of the electrical power systems that ensures DC power to key safety-related equipment required to operate during DBAs is reduced to at least the required minimum electrical power source. Based on the availability of the electrical power system to support the safety functions, the NRC staff finds the proposed change to TS 3.8.4, Condition A, acceptable.

TS 3.8.4, Condition A, is associated with Division 1 125 Vdc and Division 2 125 Vdc systems for each unit. TS 3.8.4 RA B.1 is associated with restoration of DC electrical power subsystems to operable status within 2 hours. The licensee proposed the option to use the RICT program to extend the existing 2-hour CT for RA B.1 to restore the required dc subsystem. The example calculation in LAR Table E1-2 indicates a RICT of 3.1 days. The safety function covered by the TS LCO is the GDC 17-related power requirement for safe shutdown of each reactor. According to LAR Table E1-1, the DSC for TS 3.8.4, Condition B, credits “one of two subsystems”. The NRC staff found that the RMA process in general and the specific RMAs for TS 3.8.4. RA B.1 are reasonable, and they are consistent with the intent of NEI 06-09-A, Section 3.4.3, for risk awareness and control during the emergent scenarios for TS 3.8.4, Condition B.

The unavailability of either Division 1 or Division 2 125 Vdc system is similar to the conditions analyzed for TS 3.8.4, Condition A. The loss of a battery will result in loss of the associated DC loads including the related DG. The loss of a Division 1 or 2 DG is evaluated under TS 3.8.1, Condition B. As stated above, in the March 31, 2021, RAI response, the licensee indicated that the response actions would be followed with the added requirement of recovery of a divisional dc system in addition to the recovery of a divisional ac system in the non-accident unit. Upon completion of these actions, the DSC of “one of two subsystems” stated in Table E1-1 of the LAR would be met.

Based on the above discussion, the NRC staff finds that during the RICT program entry for TS 3.8.4, Condition B, the DID of the electrical power systems that ensures DC power to key safety-related equipment required to operate during DBAs is reduced to at least the required minimum electrical power source. Based on the availability of the electrical power system to support the safety functions, the NRC staff finds the proposed change to TS 3.8.4, Condition B, acceptable.

TS 3.8.4, Condition E

TS 3.8.4, Condition E, is associated with Division 2 125 Vdc systems for the opposite unit. TS 3.8.4 RA E.1 is associated with restoration of DC electrical power subsystems to operable status within 7 days. The licensee proposed the option to use the RICT program to extend the existing 7-day CT for RA E.1 to restore the required DC subsystem. The example calculation in LAR Table E1-2 indicates a RICT of 30 days. The safety function covered by the TS LCO is the GDC 17-related power requirement for safe shutdown of each unit. According to LAR Table E1-1, the DSC for TS 3.8.4, Condition E, credits "one subsystem". The loss of a battery system will result in loss of its associated dc loads including the related DG. The loss of a Division 2 DG, as evaluated for TS 3.8.1, Condition B, is most significant when it occurs on the non-accident unit concurrent with an accident in the opposite unit and a station LOOP. That analyzed condition is discussed under TS 3.8.1, Condition B, and envelopes all conditions under which a Division 2 125 Vdc system is lost or is unavailable. The NRC staff found that the RMA process in general and the specific RMAs for TS 3.8.4. RA E.1 are reasonable, and they are consistent with the intent of NEI 06-09-A, Section 3.4.3, for risk awareness and control during the emergent scenarios for TS 3.8.4, Condition E.

Based on the above discussion, the NRC staff finds that during the RICT program entry for TS 3.8.4, Condition E, the DID of the electrical power systems that ensures DC power to key safety-related equipment required to operate during DBAs is reduced to at least the required minimum electrical power source. Based on the availability of the electrical power system to support the safety functions, the NRC staff finds the proposed change to TS 3.8.4, Condition E, acceptable.

TS 3.8.7, Condition A

The licensee proposed the option to use the RICT program to extend the existing 8-hour CT for RA A.1 to restore the required Division 1 and Division 2 AC subsystems. The example calculation in LAR Table E1-2 indicates a RICT of 0.0 days (i.e., the RICT program will not be entered). The safety function covered by the TS LCO is the GDC 17-related power requirement for safe shutdown of each unit. According to Table E1-1, the DSC for TS 3.8.7, Condition A, credits "one of two subsystems".

The TS is related to onsite AC power distribution systems for Divisions 1 and/or 2 in one of the two units. For the loss of a single AC distribution subsystem, the condition is similar to the loss of the associated DG discussed under the NRC staff's evaluation for TS 3.8.1, Condition B, for unavailability of the associated DG. The loss of either DG in the Division 1 and Division 2 AC subsystems was analyzed previously for TS 3.8.1, Condition B, and the loss of both DGs simultaneously was analyzed for TS 3.8.1, Condition C. Both of those conditions were found to be acceptable. Since Divisions 1 and 2 are independent of each other, the loss of only one of them is acceptable consistent with the DSC of "one subsystem" specified in Table E1-1 of the LAR. However, if both Divisions 1 and 2 onsite AC systems are concurrently unavailable, this would result in an LOF, as the unit would have no capability to safely shut down as illustrated by the loss of both Division 1 and 2 ESF 4.16 kV buses for a unit. Thus, the licensee proposed a corresponding note for this TS stating it would not be applicable for RICT when a LOF occurs.

Based on the above discussion, the NRC staff finds that during the RICT program entry for TS 3.8.7, Condition A, the DID of the electrical power systems that ensures power to key safety-related equipment required to operate during DBAs is reduced to at least the required minimum electrical power source. Based on the availability of the electrical power system to

support the safety functions, the NRC staff finds the proposed change to TS 3.8.7, Condition A, acceptable.

In addition, for TS 3.8.7, Condition A, the licensee has an estimated RICT with a note indicating that the RICT program is not applicable for this TS condition if a LOF occurs. The NRC staff finds this acceptable.

TS 3.8.7, Condition B

The licensee proposed the option to use the RICT program to extend the existing 2-hour CT for RA B.1 to restore the required Division 1 and Division 2 DC subsystems. The example calculation in LAR Table E1-2 indicates a RICT of 0.1 days (2.4 hours). The safety function covered by the TS LCO is the GDC 17-related power requirement for safe shutdown of each reactor. According to LAR Table E1-1, the DSC for TS 3.8.7, Condition B, credits "one of two subsystems."

TS 3.8.7 is related to inoperability of Divisions 1 and/or 2 125 Vdc systems in one unit. For the loss of a single DC distribution subsystem, the condition is similar to the loss of the associated DG discussed in the NRC staff's evaluation for TS 3.8.1, Condition B, for unavailability of the associated DG. The inoperability of both Division 1 and Division 2 125 Vdc subsystems results in the complete loss of shutdown capability for the affected unit. The inoperability of Division 1 125Vdc subsystem renders the associated Division 1 ESF loads inoperable. This condition is similar to the loss of DG 0 configuration described in the NRC staff's evaluation for TS 3.8.1, Condition B. The inoperability of the Division 2 125Vdc subsystem is discussed above in the staff's evaluation for TS 3.8.4 for which, SBO contingency actions, addressed in the March 31, 2021, RAI response, may need to be invoked in accordance with plant procedures. The corresponding loss of any DG or two DGs was analyzed in the staff's evaluations for TS 3.8.1, Conditions B and C, respectively, and found to be acceptable. In the unlikely event that the 125 Vdc Division failed, the net effect is no power to all dc connected loads including the corresponding DG. Since Divisions 1 and 2 are independent of each other, the loss of only one of them is acceptable. However, if both Division 1 and 2 onsite DC systems are concurrently unavailable, this results in an LOF. Thus, the licensee proposed a corresponding note for this TS that it would not be applicable for RICT when a LOF occurs.

Based on the above discussion, the NRC staff finds that during the RICT program entry for TS 3.8.7, Condition B, the DID of the electrical power systems that ensures power to key safety-related equipment required to operate during DBAs is reduced to at least the required minimum electrical power source. Based on the availability of the electrical power system to support the safety functions, the NRC staff finds the proposed change to TS 3.8.7, Condition B, acceptable.

In addition, for TS 3.8.7, Condition B, the licensee has an estimated RICT which is only slightly greater than the existing CT for this TS which means configuration risk will be increased very slightly.

TS 3.8.7, Condition D

TS 3.8.7, Condition D, is associated with Division 2 125 Vdc and AC systems for the opposite unit. TS 3.8.4 RA D.1 is associated with restoration of AC and DC electrical power subsystems to operable status within 7 days. The licensee proposed the option to use the RICT program to extend the existing 7-day CT for RA D.1 to restore the required AC and DC subsystem. The example calculation in Table E1-2, "Example RICT Calculations," indicates a RICT of 30 days.

The safety function covered by the TS LCO is the GDC 17-related power requirement for safe shutdown of each reactor. According to Table E1-1, the DSC for TS 3.8.4, Condition E, is “one subsystem”.

The NRC staff’s evaluation of loss of the DC subsystem in Division 2 of the opposite unit is specifically discussed above for TS 3.8.4, Condition E, with the loss of an opposite unit Division 2 AC system discussed above for TS 3.8.1, Condition B. Even the loss of both the AC and DC subsystems for opposite unit Division 2 is acceptable because the other two ESF divisions for that unit are available for its safe shutdown.

Based on the above discussion, the NRC staff finds for TS 3.8.7, Condition D, the DID of the electrical power systems that ensures power to key safety-related equipment required to operate during DBAs is reduced to at least the required minimum electrical power source. Based on the availability of the electrical power system to support the safety functions, the NRC staff finds the proposed change to TS 3.8.7 acceptable.

The NRC staff reviewed the proposed changes to LaSalle’s electrical power systems TS 3.8 that would add or change CTs evaluated in accordance with the RICT program for certain required actions of the proposed TS. The NRC staff finds that while redundancy is not maintained, 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, 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.

3.2.2.3 Key Principle 2: Conclusions

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

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

Based on the above, the NRC staff finds that the licensee’s proposed changes are consistent with the NRC-endorsed guidance prescribed in the NEI 06-09, Revision 0-A, and satisfy the second key principle in RG 1.177. Additionally, the RC staff concludes that the changes are 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. In the LAR, the licensee proposed to add a new program, "Risk Informed Completion Time Program," in Section 5.0, "Administrative Controls," of the TSs, which would require adherence NEI 06–09, Revision 0-A.

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

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, Revision 0-A, is limited to the inoperable train, loop, or component.

Based on the above, the NRC staff finds that the design-basis analyses for LaSalle remain applicable and unchanged. The NRC staff concludes that the proposed changes meet the third key 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-A, Revision 0, 'Risk-Managed Technical Specifications (RMTS) Guidelines.'"

NEI 06-09-A provides a methodology for a licensee to evaluate and manage the risk impact of extensions to TS CTs. Permanent changes to the fixed TS CTs are typically evaluated by using the three-tiered approach described in Chapter 16.1 of the SRP, RG 1.177, Revision 1, and RG 1.174, Revision 2. This approach addresses the calculated change in risk as measured by the change in core damage frequency (CDF) and large early release frequency (LERF), as well as the incremental conditional core damage probability 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. In addition, 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) scope and acceptability of the PRA models and their application to the proposed changes, and (2) a review of the PRA results and insights described in the licensee's application.

3.2.4.1.1 PRA Scope

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 0-A 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.

The NRC staff evaluated the PRA acceptability information provided by the licensee in Enclosure 2 of the January 31, 2020, 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 LaSalle PRA model with modifications is used as the CRMP model as described in Section 3.2.4.1.3 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. In its October 29, 2020, response to DRA/APLA RAI 08, the licensee confirmed that the LaSalle PRA does not credit FLEX (i.e., diverse and flexible coping strategies).

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

3.2.4.1.2 Evaluation of PRA Acceptability for Internal Events and Internal Fires

IEPRA (Includes Internal Flooding)

In Enclosure 2, Section 3, of the January 31, 2020, submittal, the licensee confirmed that the LaSalle internal events (includes flooding) PRA (IEPRA) model received a peer review in April 2008 using NEI 05-04 (Reference 22), the ASME (American Society of Mechanical Engineers) PRA Standard ASME RA-Sc-2007 (Reference 23) and RG 1.200, Revision 1

(Reference 24). LaSalle confirmed that the facts and observations (F&Os) identified from the 2008 IEPRA (includes internal floods) peer review were addressed as a part of the PRA maintenance process during the periodic PRA updates. Furthermore, a gap analysis was performed as a part of the 2014 PRA update to assess the IEPRA (includes internal floods) using ASME/ANS (American Nuclear Society) PRA Standard RA-Sa-2009. Two subsequent independent assessments for closure of F&Os using Appendix X to NEI 05-04, 07-12, and 12-13 (Reference 25), as accepted, with conditions by the NRC staff, were performed in 2017 and 2019 for the IEPRA (includes internal floods). The NRC staff performed a review of the remaining open F&Os along with the dispositions provided by the licensee in Table E2-1 of the LAR and concluded that the dispositions were sufficient for this application because the F&O was either resolved by subsequent actions or the resolution of the F&O would not impact the RICT program.

The NRC staff finds that the LaSalle IEPRA (includes internal floods) was appropriately peer reviewed consistent with RG 1.200, Revision 2, F&Os closed consistent with Appendix X guidance, as accepted, with conditions by the NRC staff, and remaining open F&Os have been appropriately assessed for impact on the RICT program. Therefore, the NRC staff concludes that the IEPRA (includes internal floods) is acceptable for use in the RICT program.

Internal Fire (FPRA)

In Enclosure 2, Section 4, of the January 31, 2020, submittal, the licensee confirmed that the LaSalle internal fire PRA (FPRA) model received a peer review in December 2015 using NEI 07-12 (Reference 26), the ASME/ANS PRA Standard RA-Sa-2009 (Reference 27), and RG 1.200, Revision 2. The licensee further confirmed that the F&Os identified from the 2015 FPRA peer review were addressed as a part of the PRA maintenance process during the subsequent PRA updates and an Independent Assessment was performed in October 2017 consistent with Appendix X, as accepted, with conditions by the NRC staff. A focused-scope peer review was performed in parallel with the Independent Assessment to assess the technical element “Fire Risk Quantification” of the PRA standard due to the large change in CDF and LERF. A subsequent independent assessment was performed in September 2019 for review of the changes made to the LaSalle FPRA. The NRC staff performed a review of the remaining open F&Os along with the dispositions provided by the licensee in Table E2-2 of the LAR. In its October 29, 2020, response to DRA/APLA RAI 01, the licensee provided an updated Table APLA-01.1 that included implementation items controlled via the licensee’s TS to address finding level F&Os 4-17 and 6-11 as stated in Table E2-2 of the LAR. The NRC staff reviewed the proposed dispositions for finding level F&Os 4-17 and 6-11 and concluded that the resolutions to address the finding level F&Os, and the completion of the corresponding implementation items is sufficient for the RICT program.

In its October 29, 2020, response to DRA/APLA RAI 02.a, the licensee explained that the guidance in NUREG-2178, Volume 1, was implemented. The licensee described that guidance from a draft version of NUREG-2178, Volume 1 (Reference 27), was incorporated into the FPRA that was peer reviewed in December 2015. The licensee further confirmed that the peer review did not identify any finding level F&Os related to guidance from the draft and that upon issuance of NUREG-2178, Volume 1 (Reference 28), the LaSalle FPRA model was reviewed and updated, as necessary, to ensure that the correct final heat release rates (HRRs) for electrical cabinets were used in the fire modeling calculations. The licensee confirmed that LaSalle does not credit incipient fire detection systems and, therefore, the guidance in NUREG-2180 is not applicable. The NRC staff concludes that the licensee’s consideration and incorporation of the guidance in NUREG-2178, Volume 1 is appropriate because it is accepted

guidance and the adjustment of HRR values does not constitute a PRA upgrade in accordance with the PRA standard.

In its October 29, 2020, response to DRA/APLA RAI 02.b, the licensee stated that for the LaSalle FPRA dependency analysis a minimum joint human error probability(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 NRC staff notes that per the guidance in Figure 6-1 of NUREG-1921 when an operator action is performed by a different crew this leads to low dependency for even high stress scenarios. Therefore, according to Table 6-1 of NUREG-1921 (Reference 29), the credit taken by the licensee for applying a lower joint HEP for combinations that include a long-term action is consistent with the guidance. The licensee also provided the results of a sensitivity study that was performed in which a minimum joint HEP of 1E-05 was applied and RICT calculations were performed for a sample of eight LCOs. The results of the sensitivity study demonstrated that the calculated RICTs did not change apart from one exception, in which the RICT increased from 11.7 to 12.0. The NRC staff concludes that the licensee's application of minimum joint HEP values is acceptable because the licensee demonstrated it meets the intent of applicable guidance, and that the minimum joint HEPs used for the LaSalle FPRA have a minimal impact on the RICT application.

In its October 29, 2020, response to DRA/APLA RAI 02.c, the licensee confirmed 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 used.

In its October 29, 2020, response to DRA/APLA RAI 02.d, the licensee explained that fire scenario development methodology used in the FPRA requires that all targets within the zone of influence (ZOI), regardless of their location in the reactor units, are selected and analyzed for fire-induced failure. The licensee further confirmed that all fires, regardless of location, are assumed to result in, at a minimum, a turbine trip in both units so a fire in the opposite unit will cause a turbine trip in the analyzed unit. The licensee provided the risk contribution of Unit 1 fires to Unit 2 fire CDF and fire LERF, approximately 5 percent and 3 percent, respectively. The NRC staff notes that although fires in the opposite unit impact fire risk and, therefore, impact the RICT calculations to a small degree, this impact is still accounted for by the licensee's fire scenario development. The NRC staff finds the licensee's treatment of fire dependencies between the units is acceptable because the risk contribution of fires originating in one unit is addressed for the other unit.

Based on its review and the above conclusions, the NRC staff finds that the LaSalle FPRA was appropriately peer reviewed consistent with RG 1.200, Revision 2, fire methodologies were appropriately considered and implemented, F&Os were closed consistent with Appendix X, as accepted, with conditions by the NRC staff, and the remaining open F&Os were adequately assessed for their impact on the RICT program. Therefore, the LaSalle FPRA is acceptable for use in the RICT program.

3.2.4.1.3 Evaluation *of* External Hazards

The NRC staff's SE for NEI 06-09, Revision 0-A, 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.

The licensee provided its assessment of external hazard risk for the RICT program in the January 31, 2020, submittal, Enclosure 4, “Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models”. The licensee states that the hazards assessed in LAR Enclosure 4, Table E4-11 are those identified for consideration in non-mandatory Appendix 6-A of the ASME/ANS PRA standard which provides a guide for identification of most of the possible external events for a plant site. The NRC staff notes that the list of hazards provided in Table E4-11 of Enclosure 4 in the LAR 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.

In LAR Enclosure 4, Section 2, the licensee states for the overall process, consistent with NUREG-1855, Revision 1, that 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 decision-making, and (3) developing a PRA model to be used in the RMAT/RICT calculation.

In LAR Table E4-11, the licensee provided a screening disposition for each non-seismic external hazard as well as other hazards and concludes that no unique PRA model for these hazards is required in order to assess configuration risk for the RICT program (with the exception of internal flooding and internal fire, which are addressed by a PRA).

The NRC staff notes that the preliminary screening criteria and progressive screening criteria used and presented in LAR Table E4-12 are the same criteria presented in the supporting requirements EXT-B1 and EXT-C1 of the ASME/ANS PRA Standard.

External Hazards Scope

The licensee addressed the risk from seismic events and other external hazards in the context of this application in Enclosure 4 to the LAR. This enclosure provided the licensee’s conservative estimate for the CDF and LERF from seismic events for use in determining the configuration risk for the RICTs identified in the LAR as discussed below. The basis for exclusion of certain hazards from consideration in the determination of RICTs due to their insignificance to the calculation of configuration risk was also provided in the same enclosure as discussed below. The licensee stated that its IPEEE external screening evaluation was updated to support this LAR.

The NRC staff reviewed Enclosure 4 to the LAR and supplemental information to determine the acceptability of the consideration of risk from seismic events and other external hazards for this application.

Seismic

The licensee explained in LAR Enclosure 4, Section 3.0, that RICT calculations will include a risk contribution from seismic events using a “seismic penalty” approach. The licensee’s approach for including the seismic risk contribution in the RICT calculation is to add a constant seismic CDF and seismic LERF to each RICT calculation. Section 3.3.5 of NEI 06-09-A 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 identified in NEI 06-09-A, is a reasonable bounding analysis which must be case-specific and technically verifiable and must be shown to be conservative from the perspective of RICT determination.

The proposed bounding seismic CDF estimate is based on using the plant-specific seismic hazard curves developed in response to the Near-Term Task Force recommendation 2.1 (Reference 29) and (Reference 30), and a plant-level high confidence of low probability of failure (HCLPF) capacity of 0.30g 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 LaSalle seismic CDF estimate are those cited for LaSalle in Table B-2 and C-2 of NRC Generic Issue 199 (GI-199) “Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants, Safety/Risk Assessment,” dated September 2, 2010 (Reference 31). The 0.30g PGA value is consistent with the LaSalle individual plant examination of external events (IPEEE) review level earthquake. Estimation of the seismic CDF is performed by convolving the PGA based seismic hazard curve for the LaSalle site using eight seismic hazard intervals with the LaSalle PGA-based HCLPF. The calculated bounding seismic CDF is 1.1E-05 per year, which is proposed to be added to each RICT calculation. The NRC staff finds that the method to determine the baseline seismic CDF is acceptable because it is consistent with the approach used in GI-199. The NRC staff used the input parameters identified by the licensee to confirm the proposed bounding seismic CDF estimate.

Concerning the proposed bounding seismic LERF estimate, the licensee states in LAR Enclosure 4, Section 3, that the bounding seismic LERF estimate is based on multiplying the estimated seismic CDF (i.e., 1.1E-05 per year) by an average seismic conditional large early release probability (SCLERP). The NRC staff notes, and the licensee acknowledged in the LAR, that the LaSalle seismic PRA was performed prior to the development of the current seismic PRA methods and standards and before the updated seismic hazard for the site was developed. The licensee provided arguments for why seismic induced structural failure of primary containment and primary containment isolation failures are not expected to be risk important based on PRA Level 2 insights from the IEPRA. Moreover, the licensee explained that it conservatively increased its estimate of the SCLERP by a factor of 10 to 0.2, which was then used to determine a seismic LERF penalty of 2.2E-06 per year, based on a seismic CDF of 1.1E-05 per year. The licensee further explained that it will use a SCLERP of 1.0 when the reactor is de-inerted to account for the possibility of a hydrogen deflagration event, resulting in a seismic LERF penalty of 1.1E-05 per year when the containment is de-inerted. The NRC staff finds the licensee’s development of a SCLERP of 0.2 acceptable because: (1) it was derived using a plant-specific seismic PRA cited in its IPEEE with an order of magnitude increase to account for uncertainty in the quality of the licensee’s IPEEE SPRA, and (2) it falls into the range of SCLERP values that NRC staff has observed for similar plants with contemporary SPRAs. Further, the NRC staff finds that the SCLERP of 1.0 when the reactor is de-inerted bounds that configuration.

The NRC staff finds that during RICTs for 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.

In summary, the NRC staff finds the licensee’s proposal to use the seismic CDF contributions of 1.1E-05 per year, and a seismic LERF contribution of 2.2E-06 per year when the containment is inerted, or a seismic LERF contribution of 1.1E-05 per year when the containment is de-inerted to be acceptable for the licensee’s RICT program for LaSalle because: (1) the licensee used

the most current site-specific seismic hazard information for LaSalle, (2) the licensee used an acceptably low plant HCLPF value of 0.3g and a combined beta factor of 0.4 consistent with the information for LaSalle in the GI-199 evaluation, (3) the licensee determined a seismic LERF penalty based on its estimate of seismic CDF combined with a SCLERP for an inerted containment based on a seismic PRA cited by its IPEEE with an order of magnitude increase to account for uncertainty in the quality of the licensee's IPEEE SPRA, (4) the SCLERP for the de-inerted containment bounds that configuration, and (5) adding baseline seismic risk 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.

Extreme Winds and Tornado Hazards

LAR Enclosure 4, Section 4, discusses the licensee's evaluation of the impact of extreme winds and tornadoes on this application. The basis for the licensee's finding of an insignificant impact of extreme winds and tornados (including tornado-generated missiles) for this application relies on the design of SSCs and a tornado missile analysis. Table E4-11 of Enclosure 4 presents the licensee's screening criteria used to disposition the risk for extreme wind and tornado hazards. Table E4-11 indicates that criterion "C1" (Event damage potential is < events for which plant is designed) was used to screen the extreme wind and tornado hazard.

Two systems were determined to be vulnerable to tornado missiles and to not be in conformance with the LaSalle design and LB (i.e., MCC/HVAC (system VC) and the Auxiliary Electrical Equipment Room HVAC (system VE)). However, the licensee screened out the tornado missile hazard because the tornado winds speeds necessary to generate missiles with velocities capable penetrating the 6-inch reinforced concrete barrier above the SSCs and causing damage is much less than 1E-06 per year. The licensee further explained that the VC and VE systems are each spatially separated by a train, with at least 20 feet between components from different trains. The licensee stated that a loss of ventilation to the control room and/or the auxiliary electric equipment room would not result in immediate failure to any safety-related or risk significant components because several hours would elapse before the affected rooms would reach temperatures that could potentially result in higher failure rates for components. The licensee further stated that procedures were available to mitigate such failures. 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.

The NRC staff finds that that the licensee has appropriately considered the risk from extreme winds and tornadoes in the proposed RICTs and 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

LAR Enclosure 4, Section 5, discusses the licensee's evaluation of the risk from the external flooding hazard. The licensee's conclusions that the impact on this application is insignificant are based on the results documented in the licensee's flood hazard reevaluation report (FHRR) for LaSalle (Reference 32), and the licensee's follow-up flooding focused evaluation (FE) for LaSalle. Table E4-11 of the same enclosure presents the licensee's screening criterion used to disposition the risk for the external flooding hazard, as "C1" (Event damage potential is < events for which plant is designed).

Furthermore, the LAR concludes that for the RICT program, there are no configuration specific considerations related to the screening assessment for the external flooding hazard. The NRC staff previously reviewed the licensee's FHRR (Reference 33) and determined that the licensee conducted the hazard reevaluation using present-day methodologies and regulatory guidance used by the NRC staff. The NRC staff previously reviewed the licensee's FE (Reference 34) and concluded that effective flood protection existed from the reevaluated flood hazards. The NRC staff's previous review of the licensee's focused evaluation noted that the licensee did not rely on any personnel actions or new modifications to the plant in order to respond to the local intense precipitation and probable maximum storm surge events.

The LAR did not describe any risk management actions to ensure that the flood protection features, which are "integral to flood protection" and important for screening of external flooding, continue to be available and functional during the proposed RICTs. In its October 1, 2020, RAI response, the licensee stated that the RICT program will rely on existing plant procedures to ensure that the normally closed exterior plant doors along the 710'-6" elevation (i.e., those doors integral to flood protection) are verified to be closed prior to heavy rainfall. The NRC staff finds that the licensee has appropriately considered the risk from external flooding in the proposed RICTs and that the external flooding hazard has an insignificant contribution to configuration risk and can be excluded from the calculation of the proposed RICTs. The NRC staff also finds that plant procedure exist to ensure that the flood protection features will be available during RICTs to manage the external flooding risk in the RICT program.

Other External Hazards

Besides the external flooding and high winds and tornados discussed above, the licensee provided a rationale for concluding there is an insignificant impact of non-seismic external hazards and other hazards for LaSalle in Table E4-11 of Enclosure 4 to the January 31, 2020, submittal. In its October 1, 2020, RAI response, the licensee further explained the CDF from turbine missiles is estimated to be less than 1E-07 per year. Based on the NRC staff's review of the information cited by the licensee, the staff 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.

3.2.4.1.4 PRA Results and Insights

The proposed change implements a process to determine TS RICTs rather than specific changes to individual TS CTs. NEI 06-09-A delineates that periodic assessment be performed of the risk incurred due to operation beyond the "front stop" CTs resulting from implementation of the RICT program and comparison to the guidance of RG 1.174, Revision 2, for small increases in risk. The licensee provided in Enclosure 5 of the submittal the estimated total CDF and LERF to demonstrate that it meets the 1E-4/year CDF and 1E-5/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.

The licensee has incorporated NEI 06-09-A into TS 5.5.17. The estimated current total CDF and LERF for LaSalle PRAs meet the RG 1.174, Revision 3 guidelines, therefore, the NRC staff concludes the PRA results and insights to be used by the licensee in the RICT program will continue to be consistent with NEI 06-09-A.

3.2.4.1.5 Key Assumptions and Uncertainty Analyses

The licensee considered PRA modeling uncertainties and their potential impact on the RICT program and identified, as necessary, the applicable RMAs to limit the impact of these uncertainties. In Enclosure 9 of the January 31, 2020, submittal, the licensee discussed the identification of key assumptions and sources of uncertainty along with providing the dispositions for impact on the risk-informed application or applicable sensitivities. The licensee evaluated the LaSalle PRA model to identify the key assumptions and sources of uncertainty for this application consistent with the RG 1.200, Revision 2, definitions, using sensitivity and importance analyses to place bounds on uncertain processes, to identify alternate modeling strategies, and to provide information to users of the PRA.

The NRC staff finds that the licensee performed an adequate assessment to identify the potential sources of uncertainty, and the identification of the key assumptions and sources of uncertainty was appropriate and consistent with the guidance in NUREG-1855, Revision 1, and associated Electric Power Research Institute (EPRI) TR-1016737 and EPRI TR-1026511, (Reference 35), and (Reference 36), respectively. Therefore, the NRC staff finds the licensee has satisfied the guidance in RG 1.177, Revision 1, and RG 1.174, Revision 2, and that the identification of assumptions and treatment of model uncertainties for risk evaluation of extended CTs is appropriate for this application and is consistent with the guidance in NEI 06-09-A.

In DRA/APLA RAI 05.a, dated September 29, 2020, the NRC staff noted that cable selection is identified as a source of FPRA modeling uncertainty because of conservatisms in the approach used by the licensee. Accordingly, the NRC staff requested the licensee provide a description of the sensitivity performed and the results to confirm that the modelling does not adversely impact future RICT calculations. In response to DRA/APLA RAI 05.a, the licensee explained that the sensitivity analysis performed consisted of removing all unknown location (UNL) modeled components thereby maximizing the calculated risk increase when those components are taken out-of-service. The sensitivity results demonstrated that all except two RICT calculations are unchanged. For the two exceptions, the change-in-risk decreased in the sensitivity cases leading to a more extended calculated RICT. Therefore, the NRC staff finds that risk is not masked by the conservative modeling of UNL components and that the licensee's treatment of UNL components is acceptable for this application.

In DRA/APLA RAI 05.b, the NRC staff noted that the results of a sensitivity study regarding vapor suppression failure probability following a vessel rupture significantly impacted the calculated RICTs when using upper bound values from NUREG/CR-6595, Revision 1 (Reference 37). The NRC staff requested justification that the bounding values used in the sensitivity study are conservative. In response to DRA/APLA RAI 05.b, the licensee explained that: (1) the upper bound failure probabilities from NUREG/CR-6595 include the contribution of several other failure modes besides vapor suppression, (2) the modelled end state is conservatively assumed to lead to large early release in all cases, (3) the failure that is more likely to lead to suppression pool bypass does not represent an immediate containment challenge, and (4) there are no RMAs that could be applied to compensate for this phenomenologically driven failure mode. Based on the above, the NRC staff finds that the risk calculated using the cited bounding values are overly conservative to provide reasonable insights for the application; and that consideration of the uncertainty associated with modeling vapor suppression would not lead to a change in the associated RMAs.

In DRA/APLA RAI 05.c, the NRC staff noted that the LAR did not discuss the uncertainty associated with modeling the hardened containment vent system (HCVS) or how it will be

treated in the RICT program. Accordingly, the NRC staff requested that the licensee provide a discussion of the uncertainty associated with modelling the HCVS in the FPRA and justification that modelling of the HCVS is sufficient for the RICT application. In response to DRA/APLA RAI 05.c, the licensee explained that after HCVS modelling was incorporated into the FPRA, a sensitivity study was performed that demonstrated that the modelling had a significant impact on fire risk. Subsequently, in October 2017, a focused-scope peer review was performed that encompassed the HCVS modelling. The licensee confirmed that F&Os generated by the focused-scope peer review closed in the September 2019, F&O closure review, the HCVS modelling was not considered a source uncertainty for this application. The NRC staff finds that the uncertainty associated with initial incorporation of HCVS modeling into the FPRA was resolved using a focused-scope peer review that encompassed the modelling and subsequent closure of all resulting finding level F&Os.

In DRA/APLA RAI 05.d, the NRC staff noted that modelling the survivability of the ECCS after containment venting was identified in the LAR as a key source of uncertainty. The licensee stated that a sensitivity study assuming the ECCS equipment would not survive post containment venting was performed demonstrating the RICT estimates would be impacted. However, the licensee concluded in the LAR that the assumption used in the sensitivity case was unrealistic and that the modelling uncertainty has a negligible impact on the RICT application. Accordingly, the NRC staff requested that the licensee provide a discussion of RMAs for TS LCOs impacted by this uncertainty and justification for why RMAs are sufficient to address this uncertainty. In response to DRA/APLA RAI 05.d, the licensee explained that a review of the importance measures of the baseline and sensitivity case results was performed to determine how the top operator actions were impacted. The licensee indicated that the importance of top operator actions was the same in the sensitivity case and baseline case, therefore, no change was proposed in the RMAs to compensate for this uncertainty. The NRC staff finds the licensee's treatment of this uncertainty is acceptable for this application because the licensee reviewed the impact of the uncertainty on proposed RMAs and found that the uncertainty had no impact on the application of RMAs.

In DRA/APLA RAI 06, the NRC staff observed that in accordance with RG 1.174, Revision 2, guidelines are based on the use of mean values and that point estimates do not account for the state-of-knowledge correlation (SOKC) between nominally independent basic event probabilities. As such, treatment of SOKC is a source of uncertainty, if it has not been accounted for in the parametric uncertainty analysis. The NRC staff requested that the licensee summarize how the SOKC investigation was performed for the PRA models used to support the RICT application and how the SOKC will be addressed for the RICT program. In response to DRA/APLA RAI 06, the licensee provided the results of an investigation into the impact of SOKC on the application and concluded that the impact is minimal, and the use of point estimate values is sufficient for the application. The NRC staff notes that the impact of SOKC is spread across many different failure modes and has a comparable impact on the results of the baseline case (i.e., all equipment required by the TS is available) as the results of the "unavailability cases" (i.e., cases in which equipment is unavailable). For this reason, and in view of the demonstration by the licensee's sensitivity study that the impact of the SOKC is small, the NRC staff finds the licensee's use of point estimate values for the RICT application is acceptable.

Based on the NRC staff's review of the licensee's dispositions provided in LAR Enclosure 9 to the identified key assumptions and sources of modeling uncertainty, and the supplemental responses provided by the licensee, the staff finds the licensee's treatment of the identified key assumptions and key sources of uncertainty for this application is consistent with NUREG-1855, Revision 1, and NEI 06-09-A.

3.2.4.1.6 PRA Scope and Acceptability Conclusions

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

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

3.2.4.1.7 Application of PRA Models in the RICT Program

The LaSalle base PRA models that are determined to be acceptable in Section 3.2.4.1.6 of this SE will be modified as an application-specific PRA model (i.e., CRMP tool), that will be used to analyze the risk for an extended CT. The CRMP model produces results (i.e., risk metrics) that are consistent with the NEI 06-09-A guidance. Throughout the entirety of the LAR, and specifically in Table E1-1, the licensee provided all information needed to support the requested LCO actions proposed for the LaSalle RICT program consistent with all the Limitations and Conditions prescribed in Section 4.0 of NEI 06-09-A.

The NRC staff did not identify any insufficiencies in the information or the CRMP tool as described in the LAR, as supplemented in the licensee's RAI responses. Furthermore, as stated in Attachment 7 of the LAR, the LaSalle "design criteria of the applicable systems are maintained…[t]he change requested in the LAR does not physically change the applicable systems." The NRC staff finds that the LaSalle PRA models and CRMP tool used will continue to reflect the as-built, as-operated plant consistent with RG 1.200, Revision 2 for ensuring PRA acceptability is maintained. Therefore, the NRC staff concludes that the proposed application of the LaSalle RICT program is appropriate for use in the adoption of TSTF-505 for performing RICT calculations.

3.2.4.2 Tier 2: Avoidance of Risk-Significant Plant Configurations

As prescribed in RG 1.177, Revision 1, the second tier evaluates the capability of the licensee to recognize and avoid risk-significant plant configurations that could result if equipment, in addition to that associated with the proposed change, is taken out of service simultaneously or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. The limits established for entry into a RICT and for RMA implementation are consistent with the guidance of NUMARC 93-01, Revision 4F, endorsed by RG 1.160, Revision 4 (Reference 38) and (Reference 39), respectively, 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 January 31, 2020, submittal, identifies three kinds of RMAs (i.e., actions to provide increased risk awareness and control, actions to reduce

the duration of maintenance activities, and actions to minimize the magnitude of the risk increase).

The LAR also explains that RMAs will be implemented, in accordance with current plant procedures, no later than the time at which the 1E-06 incremental core damage probability (ICDP) or 1E-07 incremental large early release probability (ILERP) threshold 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, and because the proposed changes are consistent with the Tier 2 guidance of RG 1.177, Revision 1, the NRC staff finds the licensee's Tier 2 program is acceptable and supports the proposed implementation of the RICT program.

3.2.4.3 Tier 3: Risk--Informed Configuration Risk Management

The 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.

The proposed RICT program establishes a CRMP based on the underlying PRA models. The CRMP is then used to evaluate configuration-specific risk for planned activities associated with the RMTS extended CT, as well as emergent conditions which may arise during an extended CT. This required assessment of configuration risk, along with the implementation of compensatory measures and RMAs, is consistent with the principle of Tier 3 for assessing and managing the risk impact of out-of-service equipment.

In Enclosure 8 of the January 31, 2020, submittal, "Attributes of the Real-Time Risk Model," the licensee confirmed that future changes made to the baseline PRA models and changes made to the online model (i.e., CRMP) are controlled and documented by plant procedures. In Enclosure 10 of the LAR, the licensee identified the attributes that the RICT program procedures will address, which are consistent with NEI 06-09-A.

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

Based on the licensee's incorporation of NEI 06-09, Revision 0-A in the TS, as discussed in LAR Attachment 1 and use of RMAs as discussed in LAR Enclosure 12, and because the proposed changes are consistent with the Tier 3 guidance of RG 1.177, the NRC staff finds the licensee's Tier 3 program is acceptable and supports the proposed implementation of the RICT program.

3.2.4.4 Key Principle 4: Conclusions

The licensee has demonstrated the technical acceptability and scope of its PRA models and alternative methods, this includes considering the impact of seismic events, non-seismic external hazards, and other hazards, and that the models can support implementation of the RICT program for determining extensions to CTs. The licensee has made proper consideration

of key assumptions and sources of uncertainty. The risk metrics are consistent with the approved methodology of NEI 06-09-A and the acceptance guidance in RG 1.177 and RG 1.174. The RICT program will be controlled administratively through plant procedures and training and follows the NRC-approved methodology in NEI 06-09-A. The NRC staff concludes that the RICT program satisfies the fourth key principle of RG 1.177 and is, therefore, acceptable.

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

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 availability of SSCs impacted by the change. Revision 2 of RG 1.174 states, in part, 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. Enclosure 11 of the January 31, 2020, submittal, states, the SSCs in the scope of the RICT program are also in the scope of 10 CFR 50.65 for the Maintenance Rule. The Maintenance Rule monitoring programs will provide for evaluation and disposition of unavailability impacts which may be incurred from implementation of the RICT program**.** In its October 29, 2020, response to DRA/APLA RAI 07, the licensee described the approach and methods used for SSC performance monitoring as described in Regulatory Position C.3.2 of RG 1.177, Revision 1, for meeting the fifth key principle of risk-informed decision-making. 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 principle of RG 1.177 and RG 1.174 because: (1) the RICT program will monitor the average annual cumulative risk increase as described in NEI 06-09-A, and use this average annual increase to ensure the program, as implemented, meets RG 1.174 guidance for small risk increases; and (2) all affected SSCs are within the Maintenance Rule program, which is used to monitor changes to the reliability and availability of these SSCs.

3.2.6 Optional Changes and Variations from TSTF-505

The NRC staff evaluated the proposed use of RICTs in the optional changes and variations stated above in Sections 2.2.4.1 and 2.2.4.2 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 and RG 1.174 have been met and concludes that the proposed optional changes and variations are acceptable.

3.2.7 Staff Conclusion

The NRC staff has evaluated the proposed changes against each of the five key principles in RG 1.177 and RG 1.174. The NRC staff concludes that the proposed changes satisfy the key principles of risk-informed decision-making identified in RG 1.174, and RG 1.177 and, therefore,

the requested adoption of the proposed changes to the TSs, implementation items, and associated guidance, is acceptable.

4.0 CHANGES TO OPERATING LICENSE

In its letter dated January 31, 2020, the licensee proposed amendments to the Renewed Facility Operation Licenses for LaSalle, Units 1 and 2, as follows:

> Adoption of Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times -RITSTF Initiative 4b"
>
> Exelon is approved to implement TSTF-505, Revision 2, modifying the Technical Specification requirements related to Completion Times (CT) for Required Actions to provide the option to calculate a longer, risk-informed CT (RICT). The methodology for using the new Risk-Informed Completion Time Program is described in NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed, Technical Specifications (RMTS) Guidelines," Revision 0, which was approved by the NRC on May 17, 2007.
>
> Exelon will complete the implementation item listed in Attachment 5 of Exelon letter to the NRC dated January 31, 2020, prior to implementation of the RICT Program. All issues identified in the attachment will be addressed and any associated changes will be made, focused-scope peer reviews will be performed on changes that are PRA upgrades as defined in the PRA standard (ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, Revision 2), and any findings will be resolved and reflected in the PRA of record prior to implementation of the RICT Program.

The NRC staff finds that the proposed license condition is acceptable because it explicitly states for implementation that the LaSalle RICT program and PRAs: (1) will be consistent with NEI 06-09-A, and (2) will address all changes consistent with RG 1.200, Revision 2.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Illinois State official was notified of the proposed issuance of the amendments on June 3, 2021. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and change surveillance requirements. 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 in the *Federal Register* on April 7, 2020 (85 FR 19511), that the amendments involve no significant hazards consideration, 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.

7.0 CONCLUSION

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

8.0 REFERENCES

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Date: September 7, 2021

SUBJECT: LASALLE COUNTY STATION, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 251 AND 237 RE: REVISE TECHNICAL SPECIFICATIONS TO ADOPT RISK-INFORMED COMPLETION TIMES TSTF-505, REVISION 2, "PROVIDE RISK-INFORMED EXTENDED COMPLETION TIMES - RITSTF INITIATIVE 4B" (EPID L-2020-LLA-0018) DATED: SEPTEMBER 7, 2021

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