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10 CFR 50.90

December 13, 2018

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Limerick Generating Station, Units 1 and 2
Renewed Facility Operating License Nos. NPF-39 and NPF-85
NRC Docket Nos. 50-352 and 50-353

Subject: License Amendment Request to Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Pursuant to 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Exelon Generation Company, LLC (Exelon) is requesting approval for proposed changes to the Technical Specifications (TS), Appendix A of Renewed Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively.

The proposed amendment would modify TS requirements to permit the use of Risk Informed Completion Times in accordance with TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b," (ADAMS Accession No. ML18183A493). A model safety evaluation was provided by the NRC to the TSTF on November 21, 2018 (ADAMS Accession No. ML18253A085).

- Attachment 1 provides a description and assessment of the proposed changes, the requested confirmation of applicability, and plant-specific verifications.
- Attachment 2 provides the existing TS pages marked up to show the proposed changes.
- Attachment 3 provides the existing TS Bases pages marked up to show the proposed changes and is provided for information only.
- Attachment 4 provides a cross-reference between the improved Standard Technical Specifications included in TSTF-505, Rev. 2 and the LGS plant-specific TS.
- Attachment 5 provides information supporting the redundancy and diversity of instrumentation governed by the TS proposed to be included as part of the RICT program in this submittal.

There are no regulatory commitments in this submittal.

These proposed changes have been reviewed and approved by the site’s Plant Operations Review Committee in accordance with the requirements of the Exelon Quality Assurance Program.

Exelon requests approval of the proposed amendment by December 13, 2019. The amendment shall be implemented within 180 days following NRC approval.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (a)(1), the analysis about the issue of no significant hazards consideration using the standards in 10 CFR 50.92 is being provided to the Commission.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), Exelon is notifying the Commonwealth of Pennsylvania of this application for license amendment by transmitting a copy of this letter and its attachments to the designated State Official.

Should you have any questions concerning this letter, please contact Glenn Stewart at (610) 765-5529.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 13th day of December 2018.

Respectfully,

James Barstow
Director - Licensing and Regulatory Affairs
Exelon Generation Company, LLC

Attachments:

1. Description and Assessment
2. Proposed Technical Specification Changes (Mark-Ups)
3. Proposed Technical Specification Bases Changes (Mark-Ups) - For Information Only
4. Cross-Reference of TSTF-505 and Limerick Generating Station Technical Specifications
5. Information Supporting Instrumentation Redundancy and Diversity

Enclosures:

1. List of Revised Required Actions to Corresponding PRA Functions
2. Information Supporting Consistency with Regulatory Guide 1.200, Revision 2
3. Information Supporting Technical Adequacy of PRA Models Without PRA Standards Endorsed by Regulatory Guide 1.200, Revision 2
4. Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models
5. Baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)
6. Justification of Application of At-Power PRA Models to Shutdown Modes
7. PRA Model Update Process
8. Attributes of the Real-Time Risk Model

9. Key Assumptions and Sources of Uncertainty
10. Program Implementation
11. Monitoring Program
12. Risk Management Action Examples

cc:	USNRC Region I, Regional Administrator	w/ attachments
	USNRC Project Manager, LGS	"
	USNRC Senior Resident Inspector, LGS	"
	Director, Bureau of Radiation Protection - Pennsylvania Department of Environmental Protection	"

ATTACHMENT 1

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Description and Assessment

1.0 DESCRIPTION

Pursuant to 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Exelon Generation Company, LLC (Exelon) is requesting approval for proposed changes to the Technical Specifications (TS), Appendix A of Renewed Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively.

The proposed amendment would modify the TS requirements related to Completion Times (CTs) for Required Actions (Action allowed outage times for LGS) to provide the option to calculate a longer, risk-informed CT. A new program, the Risk-Informed Completion Time (RICT) Program, is added to TS Section 6, Administrative Controls.

The methodology for using the RICT 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. Adherence to NEI 06-09-A is required by the RICT Program.

The proposed amendment is consistent with TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b." However, only those Required Actions described in Attachment 4 and Enclosure 1, as reflected in the proposed TS markups provided in Attachment 2, are proposed to be changed, because some of the modified Required Actions in TSTF-505 are not applicable to LGS and there are some plant-specific Required Actions not included in TSTF-505 that are included in this proposed amendment.

2.0 ASSESSMENT

2.1 <u>Applicability of Published Safety Evaluation</u>

Exelon has reviewed TSTF-505, Revision 2, and the model safety evaluation dated November 21, 2018 (ADAMS Accession No. ML18253A085). This review included the information provided to support TSTF-505 and the safety evaluation for NEI 06-09-A. As described in the subsequent paragraphs, Exelon has concluded that the technical basis is applicable to LGS, Units 1 and 2, and supports incorporation of this amendment in the LGS TS.

2.2 Verifications and Regulatory Commitments

In accordance with Section 4.0, Limitations and Conditions, of the safety evaluation for NEI 06-09-A, the following is provided:

1. Enclosure 1 identifies each of the TS Required Actions to which the RICT Program will apply, with a comparison of the TS functions to the functions modeled in the probabilistic risk assessment (PRA) of the structures, systems and components (SSCs) subject to those actions.

2. Enclosure 2 provides a discussion of the results of peer reviews and self-assessments conducted for the plant-specific PRA models which support the RICT Program, as required by Regulatory Guide (RG) 1.200, Section 4.2.

3. Enclosure 3 is not applicable since each PRA model used for the RICT Program is addressed using a standard endorsed by the Nuclear Regulatory Commission.

4. Enclosure 4 provides appropriate justification for excluding sources of risk not addressed by the PRA models.

5. Enclosure 5 provides the plant-specific baseline core damage frequency (CDF) and large early release frequency (LERF) to confirm that the potential risk increases allowed under the RICT Program are acceptable.

6. Enclosure 6 is not applicable since the RICT Program is not being applied to shutdown modes.

7. Enclosure 7 provides a discussion of the licensee's programs and procedures that assure the PRA models that support the RICT Program are maintained consistent with the as-built, as-operated plant.

8. Enclosure 8 provides a description of how the baseline PRA model, which calculates average annual risk, is evaluated and modified for use in the Real-Time Risk (RTR) tool to assess real-time configuration risk, and describes the scope of, and quality controls applied to, the RTR tool.

9. Enclosure 9 provides a discussion of how the key assumptions and sources of uncertainty in the PRA models were identified, and how their impact on the RICT Program was assessed and dispositioned.

10. Enclosure 10 provides a description of the implementing programs and procedures regarding the plant staff responsibilities for the RICT Program implementation, including risk management action (RMA) implementation.

11. Enclosure 11 provides a description of the implementation and monitoring program as described in NEI 06-09-A, Section 2.3.2, Step 7.

12. Enclosure 12 provides a description of the process to identify and provide RMAs.

2.3 <u>Optional Changes and Variations</u>

Exelon is proposing the following variations from the TS changes described in TSTF-505, Revision 2, or the applicable parts of the NRC staff's model safety evaluation dated November 21, 2018. These options were recognized as acceptable variations in TSTF-505 and the NRC staff's model safety evaluation.

The TSTF-505 markups applicable to LGS are based on NUREG-1433, "Standard Technical Specifications General Electric BWR/4 Plants," which includes Conditions, Required Actions, and Completion Times (CTs) whereas the LGS TS include Actions which are a combination of all three of these (note that CTs are referred to as allowed outage times (AOTs) for LGS). For the purposes of this license amendment request, the terminology used will be consistent with

TSTF-505 and NEI 06-09-A as much as possible, except in those places where it is appropriate to use the LGS plant-specific terminology. These differences are administrative and do not affect the applicability of TSTF-505 to the LGS TS.

Note also that, in several instances, the LGS TS use different numbering and titles than the Standard Technical Specifications (STS) on which TSTF-505 was based. These differences are administrative and do not affect the applicability of TSTF-505 to the LGS TS. Only TS changes consistent with the LGS design and TS are included. Attachment 4 provides specific information.

Attachment 4 is a cross reference that provides a comparison between the NUREG-1433 Required Actions included in TSTF-505 and the LGS Actions included in this license amendment request. The attachment includes a summary description of the referenced Required Actions, which is provided for information purposes only and is not intended to be a verbatim description of the Required Action. The cross reference identifies the following:

1. LGS Actions that have identical numbers to the corresponding NUREG-1433 Required Actions are not deviations from TSTF-505, except for administrative deviations (if any) such as formatting. These deviations are administrative with no impact on the NRC's model safety evaluation dated November 21, 2018.

2. LGS Actions that have different numbering than the NUREG-1433 Required Actions are an administrative deviation from TSTF-505 with no impact on the NRC's model safety evaluation dated November 21, 2018.

3. For NUREG-1433 Required Actions that are not contained in the LGS TS, the corresponding TSTF-505 mark-ups for the Required Actions are not applicable to LGS. This is an administrative deviation from TSTF-505 with no impact on the NRC's model safety evaluation dated November 21, 2018.

4. The model application provided in TSTF-505, Revision 2, includes an attachment for typed, camera-ready (revised) TS pages reflecting the proposed changes. LGS is not including such an attachment due to the number of TS pages included in this submittal that have the potential to be affected by other unrelated license amendment requests and the straightforward nature of the proposed changes. Providing only mark-ups of the proposed TS changes satisfies the requirements of 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," in that the mark-ups fully describe the changes desired. This is an administrative deviation from TSTF-505 with no impact on the NRC's model safety evaluation dated November 21, 2018. Because of this deviation, the contents and numbering of the attachments for this amendment request differ from the attachments specified in the model application in TSTF-505.

5. There are several plant-specific LCOs and associated Actions for which LGS is proposing to apply the RICT Program that are variations from TSTF-505 as identified in Attachment 4 with additional justification provided below:

- TS 3.3.1.a – Reactor Protection System (RPS) Instrumentation; Number of inoperable channels in either trip system for one or more Functional Units less than the minimum required operable channels per trip system.

  The requirements of TS 3.3.1, Action a. ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. Application of a RICT to TS 3.3.1, Action a. allows the operator time to evaluate and repair any discovered inoperabilities and is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

- TS 3.3.3.c.1/3.3.3.c.2 - Emergency Core Cooling System Actuation Instrumentation; Either Automatic Depressurization System (ADS) trip system subsystem inoperable.

  The ADS automatically controls five of the safety relief valves (SRVs) that are installed on the main steam lines inside the primary containment. The valves are dual-purpose in that they relieve pressure by normal mechanical action or by automatic action of an electric-pneumatic control system. The depressurization by automatic action of the control system is intended to reduce the pressure during a LOCA in which the High Pressure Coolant Injection (HPCI) system is not available so that the Core Spray (CS) system and/or Low Pressure Coolant Injection (LPCI) system can inject water into the reactor vessel.

  The ADS has two independent and redundant trip systems. Each trip system controls one of the two independent and redundant solenoid valves associated with each ADS valve. The initiating circuits for each trip system are also redundant.

  TS 3.3.3, Action c involves either ADS trip system subsystem being inoperable. Action c.1 provides a longer completion time if HPCI and the Reactor Core Isolation Cooling (RCIC) systems are operable. If HPCI and RCIC are not operable, then Action c.2 specifies a shorter completion time. In either case, the redundant ADS trip system subsystem is operable under this TS condition. Therefore, application of a RICT for TS 3.3.3, Actions c.1 or c.2 will not adversely affect the ability of the ADS to perform its intended safety function.

- TS 3.3.4.1.d – Anticipated Transient Without Scram (ATWS) Recirculation Pump Trip System Instrumentation; One trip system inoperable.

  The ATWS-RPT contributes to the mitigation of the consequences of an ATWS event by tripping the recirculation pumps early in the event, reducing core flow and thereby reducing the core power generation.

Low reactor water level or high reactor pressure Redundant Reactivity Control System (RRCS) signals cause a trip of the recirculation pump drive motor breakers. There are two separate divisions of instrumentation with divisional power sources, each one with two pressure sensors and two level sensors. A reactor vessel high dome pressure signal from either division will immediately trip both recirculation pump motors. A reactor vessel low water level signal from either division will trip both recirculation pump motors after a 10-second delay. This reduction in core flow protects the vessel and fuel during the ATWS event by limiting core power during the time required for the scram air header to depressurize sufficiently to open the scram valves.

Both sensors in either division (i.e., two level sensors in one division or two pressure sensors in one division) are required to generate a trip signal. The ATWS-RPT pump breakers are the same ones used in the end-of-cycle recirculation pump trip (EOC-RPT). There are two breakers in series in each pump motor feed; the control logic of each breaker is assigned to a separate safety division.

Manual initiation of RRCS without reactor high pressure or reactor low level 2 does not trip the recirculation pump drive motor breaker; however, after manual initiation of RRCS, the breaker trip will occur if either reactor high pressure or low level occur.

The ATWS-RPT trip circuitry is separate from and independent of the EOC-RPT trip circuitry. Separate trip coils are used in each breaker (one for ATWS-RPT and one for EOC-RPT). The trip coils are fed from RPS power supplies.

TS 3.3.4.1.d is for one ATWS-RPT trip system inoperable. Trip capability is maintained through the other trip system. Therefore, application of a RICT for this Action will not adversely affect the ability of the ATWS-RPT to perform its intended safety function.

- TS 3.3.4.2.d – End-of-Cycle Recirculation Pump Trip System Instrumentation; One trip system inoperable.

  The purpose of the end-of-cycle recirculation pump trip (EOC-RPT) is to protect the integrity of the fuel cladding during fast pressurization transients, especially turbine trips and generator load rejection events. It supplements the reactor scram function during these events. The trip of the reactor recirculation pumps early in these transient events decreases the magnitude of the power excursion by adding negative reactivity to the core, consequently resulting in lower thermal operating limits.

  Each EOC-RPT system trips both recirculation pumps, reducing coolant flow to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system.

Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system.

For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

TS 3.3.4.2.d is for one EOC-RPT trip system inoperable. Trip capability is maintained through the other trip system. Therefore, Application of a RICT for this Action will not adversely affect the ability of the EOC-RPT to perform its intended safety function.

- TS 3.5.1.b.5 – ECCS – Operating; Three LPCI subsystems inoperable with both Core Spray subsystems operable.

  The ECCS is designed to provide protection against postulated LOCAs caused by ruptures in primary system piping. The functional requirements (e.g., coolant delivery rates), specified in the current ECCS-LOCA analysis are such that the system performance under all LOCA conditions postulated in the design satisfies the requirements of 10CFR50.46, "Acceptance Criteria for Emergency Core Cooling System for Light-Water-Cooled Nuclear Power Reactors."

  The ECCS has built-in redundancy so that adequate cooling can be provided, even in the event of specified failures. As a minimum, the following equipment makes up the ECCS:

  1. One HPCI system
  2. Two Core Spray (CS) loops
  3. Four Low Pressure Coolant Injection (LPCI) loops
  4. One ADS

  As discussed in UFSAR Section 6.3.1.1.2, certain TS limiting conditions for operation (LCOs) are based on ECCS requirements as given in NEDO-24708A. This document, prepared in response to NRC questions arising from licensee responses to I.E. Bulletin 79-08 (Events relevant to boiling water power reactors identified during Three Mile Island incident), specifies the minimum ECCS system requirements to successfully terminate a transient or LOCA initiating event (with scram) assuming multiple failures with realistic conditions. For the postulated suction line breaks (including DBA), one low pressure ECCS (one LPCI pump or one CS loop [two pumps]) and ADS to depressurize, thereby allowing the low-pressure ECCS to inject, is adequate to re-flood the vessel and

maintain core cooling sufficient to preclude fuel damage. NEDC-30936P-A, specifically applicable to LGS, references NEDO-24708A and reaffirms that one low pressure ECCS will re-flood the vessel and maintain core cooling. Application of a RICT for this Action will not adversely affect the ability of the ECCS to perform its intended safety function.

- TS 3.6.1.3.a.1 – Primary Containment Air Lock; One primary containment air lock door inoperable.

  This TS correlates to NUREG-1433, TS 3.6.1.2, Condition A, which was excluded from TSTF-505 because the Condition contains mitigating actions and requires periodic performance of an action but does not include a restoration action. For LGS, TS 3.6.1.3, Action a.1 contains mitigating actions; however, the LGS Action also includes a restoration action with an allowed outage time of 24 hours, which meets the criteria established by TSTF-505 for inclusion in this LAR.

- TS 3.6.2.3.a, Footnote ** - Residual Heat Removal (RHR) Suppression Pool Cooling (SPC); One RHR suppression pool cooling subsystem inoperable during Residual Heat Removal Service Water (RHRSW) subsystem piping repairs.

  See TS 3.7.1.1.a.3.a) and a.3.b) below.

- TS 3.6.5.3.a.1 (Unit 1)/TS 3.6.5.3.a.2 (Unit 2) – Standby Gas Treatment System (SGTS); One SGTS subsystem inoperable.

  The TSTF-505 markup for this TS indicates that a quantitative RICT cannot be performed for this TS; however, the SGTS is modeled in the LGS PRA. Therefore, a quantitative RICT can be performed for this LGS TS.

  The SGTS is common to both Units 1 and 2. Two redundant 100% capacity SGTS fans are provided for use in conjunction with the SGTS filter trains. The SGTS is actuated automatically in its safety-related mode of operation. Both SGTS filter trains are maintained in the open position. Upon receipt of a secondary containment isolation signal, both of the SGTS fans are started and the associated controls are activated to open or modulate appropriate dampers and valves so that the system function is accomplished. Following the initial fan start, the operators may elect to place one of the SGTS fans in the standby position.

  The SGTS is designed to preclude direct exfiltration of contaminated air from the secondary containment following a postulated accident or an abnormal occurrence which could result in abnormally high airborne radiation in the secondary containment. Equipment for the common portions of the subsystems is powered from the Unit 1 Class 1E buses, and all power circuits meet IEEE 279 and IEEE 308 requirements to ensure power availability from the standby diesel generator sets in the event of loss of normal offsite ac power. Redundant

components are provided where necessary to ensure that a single failure does not impair or preclude system operation.

With one SGTS subsystem inoperable, the remaining operable subsystem is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single failure in the operable subsystem could result in the radioactivity release control function not being adequately performed. The allowed outage time is based on consideration of such factors as the availability of the redundant SGTS subsystem and the low probability of a design basis accident occurring during this period of inoperability. Application of a RICT for this Action will not adversely affect the ability of the SGTS to respond to a postulated accident.

- TS 3.6.5.3.a.3 (Unit 2) – Standby Gas Treatment System (SGTS); One SGTS subsystem inoperable and the other SGTS subsystem with an inoperable Unit 1 diesel generator. See TS 3.6.5.3.a.1 (Unit 1)/TS 3.6.5.3.a.2 (Unit 2) above.

  The SGTS is common to Units 1 and 2 and consists of two independent subsystems. The power supplies for the common portions of the subsystems are from Unit 1 safeguard busses; therefore, the inoperability of these Unit 1 supplies (e.g., diesel generators) are addressed in the SGTS Action statements to ensure adequate onsite power sources to SGTS for its Unit 2 function during a loss of offsite power event. The allowable out of service times are consistent with those in the Unit 1 TS for SGTS and AC electrical power supply out of service condition combinations. Application of a RICT for this Action will not adversely affect the ability of the SGTS to respond to a postulated accident.

- TS 3.6.5.3.a.4 (Unit 2) – Standby Gas Treatment System (SGTS); Unit 1 diesel generators for both SGTS subsystems inoperable.

  See TS 3.6.5.3.a.3 (Unit 2) above.

- TS 3.7.1.1.a.3.a) and a.3.b) – Residual Heat Removal Service Water (RHRSW) System.

  These TS were implemented as a result of Amendment No. 203 to Facility Operating License No. NPF-39 and Amendment No.165 to Facility Operating License No. NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively, dated July 29, 2011. These TS and associated footnotes allow the 72-hour allowed outage time (AOT) for the Suppression Pool Cooling (SPC) mode of the Residual Heat Removal (RHR) system (TS 3.6.2.3, Action a).; the Residual Heat Removal Service Water (RHRSW) system (TS 3.7.1.1, Action a.3); the Emergency Service Water (ESW) system (TS 3.7.1.2, Action a.3); and the A.C. Sources -Operating [Emergency Diesel Generators (EDGs)] (TS 3.8.1.1, Actions b. and e.1) to be extended up to 7 days during repairs of the RHRSW subsystem piping.

These TS support the replacement of large diameter piping in both the 'A' and 'B' RHRSW return headers, one at a time, which requires the longer AOTs in order to accomplish the work. Placing one RHRSW return header out of service makes one RHRSW subsystem inoperable, one ESW loop inoperable (but available), one loop of SPC mode of RHR inoperable and two EDGs per unit inoperable (but available); however, the safety function of the affected systems can still be performed by the remaining operable subsystems assuming no single failure occurs during the extended AOT.

The AOT extension is only allowed once every other calendar year, for each unit, with the opposite unit shut down, reactor vessel head removed, and reactor cavity flooded, and certain compensatory measures in effect.

During repairs of one RHRSW subsystem piping, TS 3.7.1.1.a.3.a) and a.3.b) require that operating restrictions be imposed to protect the opposite (non-affected) subsystem of RHRSW and the other affected systems and subsystems, e.g., ESW and EDGs, to ensure that the safety function of the unaffected systems and subsystems is maintained. Application of a RICT during the RHRSW piping repairs will not impact these operating restrictions. In addition, various compensatory measures, established as regulatory commitments controlled under the Exelon commitment management program, are implemented to reduce the risk of performing the RHRSW piping repairs. These compensatory measures will continue to be implemented and remain unchanged by application of a RICT during RHRSW piping repairs.

- TS 3.7.1.1.a.6 – Residual Heat Removal Service Water (RHRSW) System; Three RHRSW pump/diesel generator pairs inoperable.

  A RHRSW pump/diesel generator pair consists of a RHRSW pump and its associated diesel generator. If either a RHRSW pump or its associated diesel generator becomes inoperable, then the RHRSW pump/diesel generator pair is inoperable.

  The RHRSW system is a safety-related system designed to supply cooling water to the RHR heat exchangers of both units. The RHRSW system is common to both reactor units and consists of two loops. Each loop services two RHR heat exchangers (one RHR heat exchanger in each unit) and provides sufficient cooling for safe shutdown cooling and accident mitigation of both units. Each loop has two pumps located in the spray pond structure. The RHRSW pumps take suction from the spray pond. One pump has the capability to supply 100% flow to one RHR heat exchanger in the associated loop. During two-unit operation, there are two heat exchangers (one per unit) required for safe shutdown and accident mitigation of both units.

  One RHRSW pump in each loop (A and B) is powered from Unit 1 power supplies and, in the event of a loss of offsite power, backup power is provided from Unit 1 EDGs. The other RHRSW pump in each loop (C and D) is similarly powered from Unit 2, and backup power is provided from Unit 2 EDGs.

TS 3.7.1.1, Actions a.6 and a.7 were added to the LGS Unit 1 TS via Amendment No. 27, dated June 20, 1989, consistent with the original LGS Unit 2 TS, to reflect two-unit operation. These Actions, and an associated footnote, provide allowed outage times for various combinations of inoperable RHRSW pumps and/or EDGs which supply backup power to RHRSW components. The allowed outage times are based on the capabilities of the remaining operable RHRSW pumps and the EDGs to respond to an accident and/or loss-of-offsite-power event. These Actions serve to enforce conservative actions only with specific combinations of inoperable components. Some combinations have other RHRSW (LCO 3.7.1.1) or EDG (LCO 3.8.1.1) Actions that are more conservative than these actions and will provide for limited acceptable safe operation. Application of a RICT for these Actions will not adversely affect the ability of the facility to respond to an accident and/or a loss of offsite power event.

- TS 3.7.1.2.a.3, Footnote # - Emergency Service Water (ESW) System; One ESW loop inoperable during RHRSW subsystem piping repairs.

  See TS 3.7.1.1.a.3.a) and a.3.b) above.

- TS 3.7.1.2.a.4 - ESW System; Three ESW pump/diesel generator pairs inoperable.

  An ESW pump/diesel generator pair consists of an ESW pump and its associated diesel generator. If either an ESW pump or its associated diesel generator becomes inoperable, then the ESW pump/diesel generator pair is inoperable.

  The Emergency Service Water (ESW) system is a safety related system, designed to supply cooling water to selected equipment on both LGS Unit 1 and Unit 2 during a loss of offsite power condition and/or loss-of-coolant accident (LOCA). It is comprised of two independent loops (A and C, or B and D). Each pump is capable of supplying 100% flow through its respective loop. Each pump can supply four emergency diesel generators (EDGs) (two per unit) and all other required cooling loads for safe shutdown for both units. The A and B pumps are powered from Unit 1 buses. The C and D pumps are powered from Unit 2 buses. Emergency backup power for the A and B pumps is supplied from the Unit 1 EDGs and for the C and D ESW pumps is supplied from the Unit 2 EDGs.

  TS 3.7.1.2, Actions a.4 and a.5 were added to the LGS Unit 1 TS via Amendment No. 27, dated June 20, 1989, consistent with the original LGS Unit 2 TS, to reflect two-unit operation. These Actions, and an associated footnote, provide allowed outage times for various combinations of inoperable ESW pumps and/or EDGs which supply backup power to ESW components. The allowed outage times are based on the capabilities of the remaining operable ESW pumps and the EDGs to respond to an accident and/or loss-of-offsite-power event. These Actions serve to enforce conservative actions only with specific combinations of inoperable components. Some combinations have other ESW (LCO 3.7.1.2) or EDG (LCO 3.8.1.1) Actions that are more conservative than these actions and

will provide for limited acceptable safe operation. Application of a RICT for these Actions will not adversely affect the ability of the facility to respond to an accident and/or a loss of offsite power event.

- TS 3.8.1.1.b, Footnote * - AC Sources – Operating; Two diesel generators (DGs) inoperable during RHRSW subsystem piping repair.

  See TS 3.7.1.1.a.3.a) and a.3.b) above.

- TS 3.8.1.1.e.1 – AC Sources – Operating; Two train systems, with one or more diesel generators inoperable.

  This TS is specific to two train systems only. When one or more diesel generators are inoperable, there is an additional action requirement, i.e., TS 3.8.1.1, Action e.1, to verify that all remaining required systems, subsystems, trains, components, and devices that depend on the operable diesel generators as a source of emergency power are also operable. This requirement is intended to provide assurance that a loss of offsite power event will not result in a complete loss of safety function of critical systems during the period when one or more of the diesel generators are inoperable. Application of a RICT for this Action will not adversely affect the ability of the facility to respond to a loss of offsite power event.

- TS 3.8.1.1.e.1, Footnote * – AC Sources – Operating; Two train systems, with one or more diesel generators inoperable during RHRSW subsystem piping repairs.

  See TS 3.7.1.1.a.3.a) and a.3.b) above.

- TS 3.8.1.1.h – AC Sources – Operating; One offsite circuit and two diesel generators inoperable.

  The operability of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The Action requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The operability of the power sources is consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least two of the onsite A.C. and the corresponding D.C. power sources and associated distribution systems operable during accident conditions coincident with an assumed loss-of-offsite power and single failure of the other onsite A.C. or D.C. source. Limerick has four onsite A.C. power sources per unit. At least two onsite A.C. and their corresponding D.C. power sources and distribution systems providing power for at least two ECCS divisions (1 Core Spray loop, 1 LPCI pump and 1 RHR pump in suppression pool cooling) are required for design basis accident mitigation as discussed in UFSAR Table 6.3-3.

With one offsite circuit and two diesel generators of the required A.C. electrical power sources inoperable, the initial action, after demonstrating the operability of the remaining A.C. sources, is to restore at least one of the required inoperable A.C. sources to an operable status with a follow-up action to restore at least two offsite circuits and at least three of the required diesel generators to operable status. Application of a RICT for this Action will not adversely affect the ability of the facility to respond to a loss of offsite power event.

6. For several of the Instrumentation Section 3.3 TS, as noted in the Attachment 2 TS markups, a footnote is added to the proposed statement "or in accordance with the Risk Informed Completion Time Program" to ensure that a RICT is not applied when the actuation/trip function is lost. Under this circumstance, TSTF-505, Rev. 2 specifies the addition of a Note that reads "Not applicable when [all] required [channels] are inoperable." Because the loss of function is dependent upon not only the number of inoperable channels, but also the combination of inoperable channels within the trip systems, Exelon has chosen to replace the TSTF-505 Note with a footnote which reads "Not applicable when trip capability is not maintained," which accomplishes the intended purpose of the TSTF-505 Note.

Exelon has determined that the application of a RICT for these LGS plant-specific LCOs is consistent with TSTF-505, Revision 2, and with the NRC's model safety evaluation dated November 21, 2018. Application of a RICT for these plant-specific LCOs will be controlled under the RICT Program. The RICT Program provides the necessary administrative controls to permit extension of Completion Times and thereby delay reactor shutdown or remedial actions, if risk is assessed and managed within specified limits and programmatic requirements. The specified safety function or performance levels of TS required structures, systems or components (SSCs) are unchanged, and the remedial actions, including the requirement to shut down the reactor, are also unchanged; only the Action allowed outage times are extended by the RICT Program.

Application of a RICT will be evaluated using the methodology and probabilistic risk guidelines contained 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 (ADAMS Accession No. ML071200238). The NEI 06-09-A, Revision 0 methodology includes a requirement to perform a quantitative assessment of the potential impact of the application of a RICT on risk, to reassess risk due to plant configuration changes, and to implement compensatory measures and risk management actions (RMAs) to maintain the risk below acceptable regulatory risk thresholds. In addition, the NEI 06-09-A, Revision 0 methodology satisfies the five key safety principles specified in Regulatory Guide 1.177, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications,” dated August 1998 (ADAMS Accession No. ML003740176), relative to the risk impact due to the application of a RICT.

Therefore, the proposed application of a RICT in the LGS plant-specific Actions is consistent with TSTF-505, Revision 2, and with the NRC staff’s model safety evaluation dated November 21, 2018.

Exelon has reviewed these proposed changes and determined that they do not affect the applicability of TSTF-505, Revision 2 to the LGS TS.

3.0 REGULATORY ANALYSIS

3.1 No Significant Hazards Consideration Determination

Exelon Generation Company, LLC (Exelon) has evaluated the proposed changes to the TS using the criteria in 10 CFR 50.92 and has determined that the proposed changes do not involve a significant hazards consideration.

Limerick Generating Station (LGS), Units 1 and 2, requests adoption of an approved change to the standard technical specifications (STS) and plant-specific technical specifications (TS), to modify the TS requirements related to Completion Times for Required Actions to provide the option to calculate a longer, risk-informed Completion Time. The allowance is described in a new program in Chapter 6, "Administrative Controls," entitled the "Risk-Informed Completion Time Program."

As required by 10 CFR 50.91(a), an analysis of the issue of no significant hazards consideration is presented below:

1. Do the proposed changes involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The proposed changes permit the extension of Completion Times provided the associated risk is assessed and managed in accordance with the NRC approved Risk-Informed Completion Time Program. The proposed changes do not involve a significant increase in the probability of an accident previously evaluated because the changes involve no change to the plant or its modes of operation. The proposed changes do not increase the consequences of an accident because the design-basis mitigation function of the affected systems is not changed and the consequences of an accident during the extended Completion Time are no different from those during the existing Completion Time.

   Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Do the proposed changes create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   The proposed changes do not change the design, configuration, or method of operation of the plant. The proposed changes do not involve a physical alteration of the plant (no new or different kind of equipment will be installed).

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Do the proposed changes involve a significant reduction in a margin of safety?

Response: No.

The proposed changes permit the extension of Completion Times provided that risk is assessed and managed in accordance with the NRC approved Risk-Informed Completion Time Program. The proposed changes implement a risk-informed configuration management program to assure that adequate margins of safety are maintained. Application of these new specifications and the configuration management program considers cumulative effects of multiple systems or components being out of service and does so more effectively than the current TS.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above, Exelon concludes that the proposed changes present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

3.2 Conclusions

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

4.0 ENVIRONMENTAL EVALUATION

The proposed changes would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed changes do not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed changes meet the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed changes.

ATTACHMENT 2

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Proposed Technical Specification Changes (Mark-Ups)

TS Pages

3/4 1-19	3/4 5-3	3/4 7-4
3/4 3-1	3/4 6-5	3/4 7-9
3/4 3-9	3/4 6-15	3/4 7-33
3/4 3-32	3/4 6-16	3/4 8-1
3/4 3-36	3/4 6-17	3/4 8-1a
3/4 3-42	3/4 6-44	3/4 8-2
3/4 3-46	3/4 6-52	3/4 8-2a
3/4 3-54	3/4 7-1	3/4 8-10
3/4 3-112	3/4 7-1a	3/4 8-10a
3/4 4-23	3/4 7-2	3/4 8-17
3/4 5-2	3/4 7-3	6-14e

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.5 The standby liquid control system shall be OPERABLE and consist of the following:

a. In OPERATIONAL CONDITIONS 1 and 2, two pumps and corresponding flow paths,

b. In OPERATIONAL CONDITION 3, a minimum of one pump and corresponding flow path.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3

ACTION:

a. With only one pump and corresponding explosive valve OPERABLE, in OPERATIONAL CONDITION 1 or 2, restore one inoperable pump and corresponding explosive valve to OPERABLE status within 7 days, or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours.

b. With standby liquid control system otherwise inoperable, in OPERATIONAL CONDITION 1, 2, or 3, restore the system to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.1.5 The standby liquid control system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that:

1. The temperature of the sodium pentaborate solution is within the limits of Figure 3.1.5-1.

2. The available volume of sodium pentaborate solution is at least 3160 gallons.

3. The temperature of the pump suction piping is within the limits of Figure 3.1.5-1 for the most recent concentration analysis.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: As shown in Table 3.3.1-1.

, or in accordance with the Risk Informed Completion Time Program,

ACTION:

Note: Separate condition entry is allowed for each channel.

a. With the number of OPERABLE channels in either trip system for one or more Functional Units less than the Minimum OPERABLE Channels per Trip System required by Table 3.3.1-1, within one hour for each affected functional unit either verify that at least one* channel in each trip system is OPERABLE or tripped or that the trip system is tripped, or place either the affected trip system or at least one inoperable channel in the affected trip system in the tripped condition.

b. With the number of OPERABLE channels in either trip system less than the Minimum OPERABLE Channels per Trip System required by Table 3.3.1-1, place either the inoperable channel(s) or the affected trip system** in the tripped conditions within 12 hours.

c. With the number of OPERABLE channels in both trip systems for one or more Functional Units less than the Minimum OPERABLE Channels per Trip System required by Table 3.3.1-1, place either the inoperable channel(s) in one trip system or one trip system in the tripped condition within 6 hours**.

d. <u>If</u> within the allowable time allocated by Actions a, b or c, it is not desired to place the inoperable channel or trip system in trip (e.g., full scram would occur), <u>Then</u> no later than expiration of that allowable time initiate the action identified in Table 3.3.1-1 for the applicable Functional Unit.

, or in accordance with the Risk Informed Completion Time Program

, or in accordance with the Risk Informed Completion Time Program.***

*For Functional Units 2.a, 2.b, 2.c, 2.d, and 2.f, at least two channels shall be OPERABLE or tripped. For Functional Unit 5, both trip systems shall have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or tripped. For Function 9, at least three channels per trip system shall be OPERABLE or tripped.

**For Functional Units 2.a, 2.b, 2.c, 2.d, and 2.f, inoperable channels shall be placed in the tripped condition to comply with Action b. Action c does not apply for these Functional Units.

*** Not applicable when trip capability is not maintained for one or more Functional Units.

3/4.3.2. ISOLATION ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The isolation actuation instrumentation channels shown in Table 3.3.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.2.-2 and with ISOLATION SYSTEM RESPONSE TIME as shown in Table 3.3.2-3.

APPLICABILITY: As shown in Table 3.3.2-1.

ACTION:

a) With an isolation actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b) With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirements for one trip system:

1. If placing the inoperable channel(s) in the tripped condition would cause an isolation, the inoperable channel(s) shall be restored to OPERABLE status within 6 hours. If this cannot be accomplished, the ACTION required by Table 3.3.2-1 for the affected trip function shall be taken, or the channel shall be placed in the tripped condition.

or

2. If placing the inoperable channel(s) in the tripped condition would not cause an isolation, the inoperable channel(s) and/or that trip system shall be placed in the tripped condition within:

   a) 12 hours for trip functions common* to RPS Instrumentation.

   b) 24 hours for trip functions not common* to RPS Instrumentation.

or in accordance with the Risk Informed Completion Time Program

* Trip functions common to RPS Actuation Instrumentation are shown in Table 4.3.2.1-1.

INSTRUMENTATION

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2 and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.

APPLICABILITY: As shown in Table 3.3.3-1

ACTION:

a. With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, declare the channel inoperable until the channel is restored to Operable status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.3-1.

c. With either ADS trip system subsystem inoperable, restore the inoperable trip system to OPERABLE status within:

   1. 7 days ~~,~~ or in accordance with the Risk Informed Completion Time Program, provided that the HPCI and RCIC systems are OPERABLE.

   2. 72 hours or in accordance with the Risk Informed Completion Time Program.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 100 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS shown in Table 4.3.3.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.3.1-1.

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shown in Table 3.3.3-3 shall be demonstrated to be within the limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times the frequency specified in the Surveillance Frequency Control Program where N is the total number of redundant channels in a specific ECCS trip system.

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION STATEMENTS

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

a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or declare the associated system inoperable.

b. With more than one channel inoperable, declare the associated system inoperable.

ACTION 31 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, declare the associated ECCS inoperable within 24 hours.

ACTION 32 - DELETED

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 24 hours or declare the associated ECCS inoperable.

ACTION 34 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. For one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or declare the HPCI system inoperable.

b. With more than one channel inoperable, declare the HPCI system inoperable.

ACTION 35 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within 24 hours or declare the HPCI system inoperable.

ACTION 36 - With the number of OPERABLE channels less than the Total Number of Channels, declare the associated emergency diesel generator and the associated offsite source breaker that is not supplying the bus inoperable and take the ACTION required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

or in accordance with the Risk Informed Completion Time Program,

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.1 The anticipated transient without scram recirculation pump trip (ATWS-RPT) system instrumentation channels shown in Table 3.3.4.1-1 shall be OPERABLE with their trip setpoints set consistent with values shown in the Trip Setpoint column of Table 3.3.4.1-2.

APPLICABILITY: OPERATIONAL CONDITION 1.

, or in accordance with the Risk Informed Completion Time Program*

ACTION:

a. With an ATWS recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.1-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 24 hours.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

   1. If the inoperable channels consist of one reactor vessel water level channel and one reactor vessel pressure channel, place both inoperable channels in the tripped condition within 24 hours, or, if this action will initiate a pump trip, declare the trip system inoperable.

   2. If the inoperable channels include two reactor vessel water level channels or two reactor vessel pressure channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours, or in accordance with the Risk Informed Completion Time Program, or be in at least STARTUP within the next 6 hours.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.1.1 Each of the required ATWS recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.4.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

* Not applicable when trip capability is not maintained.

INSTRUMENTATION

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 29.5% of RATED THERMAL POWER.

, or in accordance with the Risk Informed Completion Time Program*

ACTION:

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

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 12 hours.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

   1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within 12 hours.

   2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or take the ACTION required by Specification 3.2.3.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or take the ACTION required by Specification 3.2.3.

, or in accordance with the Risk Informed Completion Time Program,

* Not applicable when trip capability is not maintained.

REACTOR CORE ISOLATION COOLING SYSTEM
ACTION STATEMENTS

ACTION 50 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or declare the RCIC system inoperable.

b. With more than one channel inoperable, declare the RCIC system inoperable.

ACTION 51 - With the number of OPERABLE channels less than required by the minimum OPERABLE channels per Trip System requirement, declare the RCIC system inoperable within 24 hours.

ACTION 52 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place at least one inoperable channel in the tripped condition within 24 hours or declare the RCIC system inoperable.

ACTION 53 - With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the inoperable channel to OPERABLE status within 24 hours or declare the RCIC system inoperable.

, or in accordance with the Risk Informed Completion Time Program,

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.9 The feedwater/main turbine trip system actuation instrumentation channels shown in the Table 3.3.9-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.9-2.

APPLICABILITY: As shown in Table 3.3.9-1.

ACTION:

, or in accordance with the Risk Informed Completion Time Program,

a. With a feedwater/main turbine trip system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.9-2, declare the channel inoperable and either place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value, or declare the associated system inoperable.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 7 days or be in at least STARTUP within the next 6 hours.

c. With the number of OPERABLE channels two less than required by the Minimum OPERABLE Channels requirement, restore at least one of the inoperable channels to OPERABLE status within 72 hours or be in at least STARTUP within the next 6 hours.

, or in accordance with the Risk Informed Completion Time Program, **

SURVEILLANCE REQUIREMENTS

4.3.9.1 Each of the required feedwater/main turbine trip system actuation instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.9.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition.

** Not applicable when trip capability is not maintained.

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.4.7 Two main steam line isolation valves (MSIVs) per main steam line shall be OPERABLE with closing times greater than or equal to 3 and less than or equal to 5 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With one or more MSIVs inoperable:

or in accordance with the Risk Informed Completion Time Program

a. Maintain at least one MSIV OPERABLE in each affected main steam line that is open and within 8 hours, either:

1. Restore the inoperable valve(s) to OPERABLE status, or

2. Isolate the affected main steam line by use of a deactivated MSIV in the closed position.

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

SURVEILLANCE REQUIREMENTS

4.4.7 Each of the above required MSIVs shall be demonstrated OPERABLE by verifying full closure between 3 and 5 seconds when tested pursuant to Specification 4.0.5.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION:

a. For the core spray system:

or in accordance with the Risk Informed Completion Time Program,

1. With one CSS subsystem inoperable, provided that at least two LPCI subsystems are OPERABLE, restore the inoperable CSS subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With both CSS subsystems inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. For the LPCI system:

1. With one LPCI subsystem inoperable, provided that at least one CSS subsystem is OPERABLE, restore the inoperable LPCI pump to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one RHR cross-tie valve (HV-51-182 A or B) open, or power not removed from one closed RHR cross-tie valve operator, close the open valve and/or remove power from the closed valves operator within 72 hours, or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

3. With no RHR cross-tie valves (HV-51-182 A, B) closed, or power not removed from both closed RHR cross-tie valve operators, or with one RHR cross-tie valve open and power not removed from the other RHR cross-tie valve operator, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

4. With two LPCI subsystems inoperable, provided that at least one CSS subsystem is OPERABLE, restore at least three LPCI subsystems to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

5. With three LPCI subsystems inoperable, provided that both CSS subsystems are OPERABLE, restore at least two LPCI subsystems to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

6. With all four LPCI subsystems inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.*

or in accordance with the Risk Informed Completion Time Program,

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

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

or in accordance with the Risk Informed Completion Time Program,

c. For the HPCI system:

1. With the HPCI system inoperable, provided the CSS, the LPCI system, the ADS and the RCIC system are OPERABLE, restore the HPCI system to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 200 psig within the following 24 hours.

2. With the HPCI system inoperable, and one CSS subsystem, and/or LPCI subsystem inoperable, and provided at least one CSS subsystem, three LPCI subsystems, and ADS are operable, restore the HPCI to OPERABLE within 8 hours, or be in HOT SHUTDOWN in the next 12 hours, and in COLD SHUTDOWN in the next 24 hours.

3. Specification 3.0.4.b is not applicable to HPCI.

d. For the ADS:

1. With one of the above required ADS valves inoperable, provided the HPCI system, the CSS and the LPCI system are OPERABLE, restore the inoperable ADS valve to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

2. With two or more of the above required ADS valves inoperable, be in at least HOT SHUTDOWN within 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

e. With a CSS and/or LPCI header ΔP instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 72 hours or determine the ECCS header ΔP locally at least once per 12 hours; otherwise, declare the associated CSS and/or LPCI, as applicable, inoperable.

f. DELETED

PRIMARY CONTAINMENT AIR LOCK

LIMITING CONDITION FOR OPERATION

3.6.1.3 The primary containment air lock shall be OPERABLE with:

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

b. An overall air lock leakage rate in accordance with the Primary Containment Leakage Rate Testing Program.

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

ACTION:

a. With one primary containment air lock door inoperable:

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

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

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

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

or in accordance with the Risk Informed Completion Time Program,

*See Special Test Exception 3.10.1.

SUPPRESSION POOL SPRAY

LIMITING CONDITION FOR OPERATION

3.6.2.2 The suppression pool spray mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHR heat exchanger and the suppression pool spray sparger(s).

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION: or in accordance with the Risk Informed Completion Time Program,

a. With one suppression pool spray loop inoperable, restore the inoperable loop to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool spray loops inoperable, restore at least one loop to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The suppression pool spray mode of the RHR system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of at least 500 gpm on recirculation flow through the RHR heat exchanger and the suppression pool spray sparger when tested pursuant to Specification 4.0.5.

c. By verifying RHR suppression pool spray subsystem locations susceptible to gas accumulation are sufficiently filled with water in accordance with the Surveillance Frequency Control Program.

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

SUPPRESSION POOL COOLING

LIMITING CONDITION FOR OPERATION

3.6.2.3 The suppression pool cooling mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one suppression pool cooling loop inoperable, restore the inoperable loop to OPERABLE status within 72 hours** or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool cooling loops inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN* within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.3 The suppression pool cooling mode of the RHR system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of at least 10,000 gpm on recirculation flow through the flow path including the RHR heat exchanger and its associated closed bypass valve, the suppression pool and the full flow test line when tested pursuant to Specification 4.0.5.

c. By verifying RHR suppression pool cooling subsystem locations susceptible to gas accumulation are sufficiently filled with water in accordance with the Surveillance Frequency Control Program.

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

** During the extended ~~7-day~~ Allowed Outage Time (AOT) specified by TS LCO 3.7.1.1, Action a.3.a) or a.3.b) to allow for RHRSW subsystem piping repairs, the 72-hour AOT for one inoperable suppression pool cooling loop may also be extended to 7 days, or in accordance with the Risk Informed Completion Time Program, for the same ~~7-day~~ period.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3 Each primary containment isolation valve and each instrumentation line excess flow check valve shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one or more of the primary containment isolation valves inoperable,** maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 4 hours, or in accordance with the Risk Informed Completion Time Program, either:

1. Restore the inoperable valve(s) to OPERABLE status, or
2. Isolate each affected penetration by use of at least one de-activated automatic valve secured in the isolated position,* or
3. Isolate each affected penetration by use of at least one closed manual valve or blind flange.*

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

b. With one or more of the instrumentation line excess flow check valves inoperable, operation may continue and the provisions of Specification 3.0.3 are not applicable provided that within 4 hours either:

1. The inoperable valve is returned to OPERABLE status, or
2. The instrument line is isolated and the associated instrument is declared inoperable.

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

c. With one or more scram discharge volume vent or drain valves inoperable, perform the applicable actions specified in Specification 3.1.3.1.

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* Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.
** Except for the scram discharge volume vent and drain valves.

3/4.6.4 VACUUM RELIEF

SUPPRESSION CHAMBER - DRYWELL VACUUM BREAKERS

LIMITING CONDITION FOR OPERATION

3.6.4.1 Three pairs of suppression chamber - drywell vacuum breakers shall be OPERABLE and all suppression chamber - drywell vacuum breakers shall be closed.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

or in accordance with the Risk Informed Completion Time Program,

a. With one or more vacuum breakers in one of the three required pairs of suppression chamber - drywell vacuum breaker pairs inoperable for opening but known to be closed, restore at least one inoperable pair of vacuum breakers to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one suppression chamber - drywell vacuum breaker open, verify the other vacuum breaker in the pair to be closed within 2 hours; restore the open vacuum breaker to the closed position within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With one position indicator of any suppression chamber - drywell vacuum breaker inoperable:

1. Verify the other vacuum breaker in the pair to be closed within 2 hours and at least once per 15 days thereafter, or

2. Verify the vacuum breaker(s) with the inoperable position indicator to be closed by conducting a test which demonstrates that the ΔP is maintained at greater than or equal to 0.7 psi for one hour without makeup within 24 hours and at least once per 15 days thereafter.

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

CONTAINMENT SYSTEMS

STANDBY GAS TREATMENT SYSTEM - COMMON SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.3 Two independent standby gas treatment subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, and when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS.

ACTION:

or in accordance with the Risk Informed Completion Time Program,

a. In OPERATIONAL CONDITION 1, 2, or 3:

   1. With one standby gas treatment subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. When (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS:

   1. With one standby gas treatment subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or suspend handling of irradiated fuel in the secondary containment and CORE ALTERATIONS. The provisions of Specification 3.0.3 are not applicable.

   2. With both standby gas treatment subsystems inoperable, if in progress, suspend handling of irradiated fuel in the secondary containment and CORE ALTERATIONS. The provisions of Specification 3.0.3. are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.5.3 Each standby gas treatment subsystem shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates with the heaters OPERABLE.

3/4.7.1 SERVICE WATER SYSTEMS

RESIDUAL HEAT REMOVAL SERVICE WATER SYSTEM - COMMON SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.1 At least the following independent residual heat removal service water (RHRSW) system subsystems, with each subsystem comprised of:

a. Two OPERABLE RHRSW pumps, and

b. An OPERABLE flow path capable of taking suction from the RHR service water pumps wet pits which are supplied from the spray pond or the cooling tower basin and transferring the water through one Unit 1 RHR heat exchanger,

shall be OPERABLE:

a. In OPERABLE CONDITIONS 1, 2, and 3, two subsystems.

b. In OPERABLE CONDITIONS 4 and 5, the subsystem(s) associated with systems and components required OPERABLE by Specification 3.4.9.2, 3.9.11.1, and 3.9.11.2.

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

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3:

1. With one RHRSW pump inoperable, restore the inoperable pump to OPERABLE status within 30 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

or in accordance with the Risk Informed Completion Time Program,

2. With one RHRSW pump in each subsystem inoperable, restore at least one of the inoperable RHRSW pumps to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. With one RHRSW subsystem otherwise inoperable, restore the inoperable subsystem to OPERABLE status with at least one OPERABLE RHRSW pump within 72 hours, unless otherwise specified in a) or b) below**, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

a) When the 'A' RHRSW subsystem is inoperable to allow for repairs of the 'A' RHRSW subsystem piping, with Limerick Generating Station Unit 2 shutdown, reactor vessel head removed and reactor cavity flooded, the 72-hour Allowed Outage Time may be extended to 7 days once every other calendar year with the following compensatory measures established:

or in accordance with the Risk Informed Completion Time Program

** Only one of these two Actions, either a.3.a) or a.3.b), may be entered on Unit 1 in a calendar year. However, if either Unit 2 TS LCO 3.7.1.1, Action a.3.a) or a.3.b) has previously been entered in the calendar year, then Unit 1 Action a.3.a) or a.3.b) may not be entered during that same calendar year.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

1) The following systems and subsystems will be protected in accordance with applicable station procedures:
- 'B' RHRSW subsystem
- 'B' ESW loop
- 'B' and 'D' RHR subsystems
- D12, D14, D22, and D24 4kV buses and emergency diesel generators
- Division 2 and Division 4 Safeguard DC, and

2) The 'A' and 'B' loop of ESW return flow shall be aligned to the operable 'B' RHRSW return header only. The ESW return valves to the 'B' RHRSW return header (i.e., HV-11-015A and HV-11-015B) will be administratively controlled in the open position and de-energized prior to entering the extended AOT. The ESW return valves to the 'A' RHRSW return header (i.e., HV-11-011A and HV-11-011B) will be administratively controlled in the closed position and de-energized as part of the work boundary.

, or in accordance with the Risk Informed Completion Time Program,

b) When the 'B' RHRSW subsystem is inoperable to allow for repairs of the 'B' RHRSW subsystem piping, with Limerick Generating Station Unit 2 shutdown, reactor vessel head removed and reactor cavity flooded, the 72-hour Allowed Outage Time may be extended to 7 days once every other calendar year with the following compensatory measures established:

1) The following systems and subsystems will be protected in accordance with applicable station procedures:
- 'A' RHRSW subsystem
- 'A' ESW loop
- 'A' and 'C' RHR subsystems
- D11, D13, D21, and D23 4kV buses and emergency diesel generators
- Division 1 and Division 3 Safeguard DC, and

2) The 'A' and 'B' loop of ESW return flow shall be aligned to the operable 'A' RHRSW return header only. The ESW return valves to the 'A' RHRSW return header (i.e., HV-11-011A and HV-11-011B) will be administratively controlled in the open position and de-energized prior to entering the extended AOT. The ESW return valves to the 'B' RHRSW return header (i.e., HV-11-015A and HV-11-015B) will be administratively controlled in the closed position and de-energized as part of the work boundary.

4. With both RHRSW subsystems otherwise inoperable, restore at least one subsystem to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* within the following 24 hours.

*Whenever both RHRSW subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by the ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

5. With two RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 30 days, or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

6. With three RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

or in accordance with the Risk Informed Completion Time Program

7. With four RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 8 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 3 or 4 with the RHRSW subsystem(s), which is associated with an RHR loop required OPERABLE by Specification 3.4.9.1 or 3.4.9.2, inoperable, declare the associated RHR loop inoperable and take the ACTION required by Specification 3.4.9.1 or 3.4.9.2, as applicable.

c. In OPERATIONAL CONDITION 5 with the RHRSW subsystem(s), which is associated with an RHR loop required OPERABLE by Specification 3.9.11.1 or 3.9.11.2, inoperable, declare the associated RHR system inoperable and take the ACTION required by Specification 3.9.11.1 or 3.9.11.2, as applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 At least the above required residual heat removal service water system subsystem(s) shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that each valve in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

*A RHRSW pump/diesel generator pair consists of a RHRSW pump and its associated diesel generator. If either a RHRSW pump or its associated diesel generator becomes inoperable, then the RHRSW pump/diesel generator pair is inoperable.

EMERGENCY SERVICE WATER SYSTEM - COMMON SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 At least the following independent emergency service water system loops, with each loop comprised of:

a. Two OPERABLE emergency service water pumps, and

b. An OPERABLE flow path capable of taking suction from the emergency service water pumps wet pits which are supplied from the spray pond or the cooling tower basin and transferring the water to the associated Unit 1 and common safety-related equipment,

shall be OPERABLE:

a. In OPERATIONAL CONDITIONS 1, 2, and 3, two loops.

b. In OPERATIONAL CONDITIONS 4, 5, and *, one loop.

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

ACTION:

a. In OPERATION CONDITION 1, 2, or 3:

1. With one emergency service water pump inoperable, restore the inoperable pump to OPERABLE status within 45 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one emergency service water pump in each loop inoperable, restore at least one inoperable pump to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. With one emergency service water system loop otherwise inoperable, declare all equipment aligned to the inoperable loop inoperable**, restore the inoperable loop to OPERABLE status with at least one OPERABLE pump within 72 hours# or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

or in accordance with the Risk Informed Completion Time Program,

*When handling irradiated fuel in the secondary containment.

**The diesel generators may be aligned to the OPERABLE emergency service water system loop provided confirmatory flow testing has been performed. Those diesel generators no aligned to the OPERABLE emergency service water system loop shall be declared inoperable and the actions of 3.8.1.1 taken.

During the extended ~~7-day~~ Allowed Outage Time (AOT) specified by TS LCO 3.7.1.1, Action a.3.a) or a.3.b) to allow for RHRSW subsystem piping repairs, the 72-hour AOT for one inoperable emergency service water system loop may also be extended to 7 days for the same ~~7-day~~ period.

or in accordance with the Risk Informed Completion Time Program

ACTION: (Continued)

or in accordance with the Risk Informed Completion Time Program,

4. With three ESW pump/diesel generator pairs** inoperable, restore at least one inoperable ESW pump/diesel generator pair** to OPERABLE status within 72 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

5. With four ESW pump/diesel generator pairs** inoperable, restore at least one inoperable ESW pump/diesel generator pair** to OPERABLE status within 8 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4 or 5:

1. With only one emergency service water pump and its associated flowpath OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or declare the associated safety related equipment inoperable and take the ACTION required by Specifications 3.5.2 and 3.8.1.2.

c. In OPERATIONAL CONDITION *

1. With only one emergency service water pump and its associated flow path OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or verify adequate cooling remains available for the diesel generators required to be OPERABLE or declare the associated diesel generator(s) inoperable and take the ACTION required by Specification 3.8.1.2. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENT

4.7.1.2 At least the above required emergency service water system loop(s) shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each automatic valve actuates to its correct position on its appropriate ESW pump start signal.

2. Each pump starts automatically when its associated diesel generator starts.

*When handling irradiated fuel in the secondary containment.

**An ESW pump/diesel generator pair consists of an ESW pump and its associated diesel generator. If either an ESW pump or its associated diesel generator becomes inoperable, then the ESW pump/diesel generator pair is inoperable.

PLANT SYSTEMS

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 The reactor core isolation cooling (RCIC) system shall be OPERABLE with an OPERABLE flow path capable of automatically taking suction from the suppression pool and transferring the water to the reactor pressure vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 with reactor steam dome pressure greater than 150 psig.

ACTION:

or in accordance with the Risk Informed Completion Time Program

a. With the RCIC system inoperable, operation may continue provided the HPCI system is OPERABLE; restore the RCIC system to OPERABLE status within 14 days. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 150 psig within the following 24 hours.

b. DELETED

c. Specification 3.0.4.b is not applicable to RCIC.

SURVEILLANCE REQUIREMENTS

4.7.3 The RCIC system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by:

1. Verifying locations susceptible to gas accumulation are sufficiently filled with water.

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

3. Verifying that the pump flow controller is in the correct position.

b. In accordance with the Surveillance Frequency Control Program by verifying that the RCIC pump develops a flow of greater than or equal to 600 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 1040 + 13, - 120 psig.*

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* The provisions of Specification 4.0.4 are not applicable, provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam pressure to less than 150 psig within the following 72 hours.

** Not required to be met for system vent flow paths opened under administrative control.

PLANT SYSTEMS

3/4.7.8 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.8 The main turbine bypass system shall be OPERABLE as determined by the number of operable main turbine bypass valves being greater than or equal to that specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 1 hour or in accordance with the Risk Informed Completion Time Program or take the ACTION required by Specification 3.2.3.c.

SURVEILLANCE REQUIREMENTS

4.7.8 The main turbine bypass system shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program:

a. By cycling each turbine bypass valve through at least one complete cycle of full travel,

b. By performing a system functional test which includes simulated automatic actuation, and by verifying that each automatic valve actuates to its correct position, and

c. By determining TURBINE BYPASS SYSTEM RESPONSE TIME to be less than or equal to the value specified in the CORE OPERATING LIMITS REPORT.

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Four separate and independent diesel generators, each with:

1. A separate day tank containing a minimum of 250 gallons of fuel,

2. A separate fuel storage system containing a minimum of 33,500 gallons of fuel, and

3. A separate fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 24 hours and at least once per 7 days thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining operable diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 24 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore the inoperable diesel generator to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

b. With two diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If either of the diesel generators became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 8 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore at least one of the inoperable diesel generators to OPERABLE status within 72 hours* or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

* During the extended ~~7-day~~ Allowed Outage Time (AOT) specified by TS LCO 3.7.1.1, Action a.3.a) or a.3.b) to allow for RHRSW subsystem piping repairs, the 72-hour AOT for two inoperable diesel generators may also be extended to 7 days or in accordance with the Risk Informed Completion Time Program for the same ~~7-day~~ period.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With three diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and perform Surveillance Requirement 4.8.1.1.2.a.4 for the remaining diesel generator, within 1 hour. Restore at least one of the inoperable diesel generators to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

d. With one offsite circuit and one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 8 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore at least two offsite circuits to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

, or in accordance with the Risk Informed Completion Time Program,

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

e. In addition to the ACTIONS above:

1. For two train systems, with one or more diesel generators of the above required A.C. electrical power sources inoperable, verify within 2 hours and at least once per 12 hours thereafter that at least one of the required two train system subsystem, train, components, and devices is OPERABLE and its associated diesel generator is OPERABLE. Otherwise, restore either the inoperable diesel generator or the inoperable system subsystem to an OPERABLE status within 72 hours* or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. For the LPCI systems, with two or more diesel generators of the above required A.C. electrical power sources inoperable, verify within 2 hours and at least once per 12 hours thereafter that at least two of the required LPCI system subsystems, trains, components, and devices are OPERABLE and its associated diesel generator is OPERABLE. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

This ACTION does not apply for those systems covered in Specifications 3.7.1.1. and 3.7.1.2.

or in accordance with the Risk Informed Completion Time Program,

* During the extended ~~7 day~~ Allowed Outage Time (AOT) specified by TS LCO 3.7.1.1, Action a.3.a) or a.3.b) to allow for RHRSW subsystem piping repairs, the 72-hour AOT may also be extended to 7 days for the same ~~7 day~~ period.

or in accordance with the Risk Informed Completion Time Program

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

f. With one offsite circuit of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore at least two offsite circuits to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and COLD SHUTDOWN within the following 24 hours.

g. With two of the above required offsite circuits inoperable, restore at least one of the inoperable offsite circuits to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours. With only one offsite circuit restored to OPERABLE status, restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

h. With one offsite circuit and two diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If either of the diesel generators became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 8 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore at least one of the above required inoperable A.C. sources to OPERABLE status within 12 hours or be in a at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore at least two offsite circuits and at least three of the above required diesel generators to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

i. Specification 3.0.4.b is not applicable to diesel generators.

, or in accordance with the Risk Informed Completion Time Program,

3/4.8.2 D.C. SOURCES

D.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 As a minimum, the following D.C. electrical power sources shall be OPERABLE:

a. Division 1, Consisting of:
   1. 125-Volt Battery 1A1 (1A1D101).
   2. 125-Volt Battery 1A2 (1A2D101).
   3. 125-Volt Battery Charger 1BCA1 (1A1D103).
   4. 125-Volt Battery Charger 1BCA2 (1A2D103).

b. Division 2, Consisting of:
   1. 125-Volt Battery 1B1 (1B1D101).
   2. 125-Volt Battery 1B2 (1B2D101).
   3. 125-Volt Battery Charger 1BCB1 (1B1D103).
   4. 125-Volt Battery Charger 1BCB2 (1B2D103).

c. Division 3, Consisting of:
   1. 125-Volt Battery 1C (1CD101).
   2. 125-Volt Battery Charger 1BCC (1CD103).

d. Division 4, Consisting of:
   1. 125-Volt Battery 1D (1DD101).
   2. 125-Volt Battery Charger 1BCD (1DD103).

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION: , or in accordance with the Risk Informed Completion Time Program

a. With one or two battery chargers on one division inoperable:

   1. Restore battery terminal voltage to greater than or equal to the minimum established float voltage within 2 hours,

   2. Verify associated Division 1 or 2 float current ≤ 2 amps, or Division 3 or 4 float current ≤ 1 amp within 18 hours and once per 12 hours thereafter, and

   3. Restore battery charger(s) to OPERABLE status within 7 days.

b. With one or more batteries inoperable due to:

   1. One or two batteries on one division with one or more battery cells float voltage < 2.07 volts, perform 4.8.2.1.a.1 and 4.8.2.1.a.2 within 2 hours for affected battery(s) and restore affected cell(s) voltage ≥ 2.07 volts within 24 hours.

   2. Division 1 or 2 with float current > 2 amps, or with Division 3 or 4 with float current > 1 amp, perform 4.8.2.1.a.2 within 2 hours for affected battery(s) and restore battery float current to within limits within 18 hours.

LIMITING CONDITION FOR OPERATION

ACTION: (Continued)

3. One or two batteries on one division with one or more cells electrolyte level less than minimum established design limits, if electrolyte level was below the top of the plates restore electrolyte level to above top of plates within 8 hours and verify no evidence of leakage(*) within 12 hours. In all cases, restore electrolyte level to greater than or equal to minimum established design limits within 31 days.

4. One or two batteries on one division with pilot cell electrolyte temperature less than minimum established design limits, restore battery pilot cell temperature to greater than or equal to minimum established design limits within 12 hours.

5. Batteries in more than one division affected, restore battery parameters for all batteries in all but one division to within limits within 2 hours.

6. (i) Any battery having both (Action b.1) one or more battery cells float voltage < 2.07 volts and (Action b.2) float current not within limits, and/or

   (ii) Any battery not meeting any Action b.1 through b.5,

   Restore the battery parameters to within limits within 2 hours.

c. With any battery(ies) on one division of the above required D.C. electrical power sources inoperable for reasons other than Action b., restore the inoperable division battery to OPERABLE status within 2 hours.

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

, or in accordance with the Risk Informed Completion Time Program

(*) Contrary to the provisions of Specification 3.0.2, if electrolyte level was below the top of the plates, the verification that there is no evidence of leakage is required to be completed regardless of when electrolyte level is restored.

LIMITING CONDITION FOR OPERATION (Continued)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

or in accordance with the Risk Informed Completion Time Program

a. With one of the above required Unit 1 A.C. distribution system divisions not energized, reenergize the division within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one of the above required Unit 1 D.C. distribution system divisions not energized, reenergize the division within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any of the above required Unit 2 and common AC and/or DC distribution system divisions not energized, declare the associated common equipment inoperable, and take the appropriate ACTION for that system.

SURVEILLANCE REQUIREMENTS

4.8.3.1 Each of the above required power distribution system divisions shall be determined energized in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignment and voltage on the busses/MCCs/panels.

c. The program shall, as allowed by 10 CFR 50.55a, meet Subsection ISTA, "General Requirements," and Subsection ISTD, "Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants," in lieu of Section XI of the ASME B&PV Code ISI requirements for snubbers, or meet authorized alternatives pursuant to 10 CFR 50.55a.

d. The 120-month program updates shall be made in accordance with 10 CFR 50.55a subject to the limitations and conditions listed therein.

l. Explosive Gas Monitoring Program

This program provides controls for potentially explosive gas mixtures contained downstream of the off-gas recombiners.

The program shall include:

a. The limit for the concentration of hydrogen downstream of the offgas recombiners and a surveillance program to ensure the limit is maintained. This limit shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

The provisions of SR 4.0.2 and SR 4.0.3 are applicable to the Explosive Gas Monitoring Program surveillance frequencies.

Insert

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.5 The standby liquid control system shall be OPERABLE and consist of the following:

a. In OPERATIONAL CONDITIONS 1 and 2, two pumps and corresponding flow paths,

b. In OPERATIONAL CONDITION 3, a minimum of one pump and corresponding flow path.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3

ACTION:

a. With only one pump and corresponding explosive valve OPERABLE, in OPERATIONAL CONDITION 1 or 2, restore one inoperable pump and corresponding explosive valve to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours.

b. With standby liquid control system otherwise inoperable, in OPERATIONAL CONDITION 1, 2, or 3, restore the system to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.1.5 The standby liquid control system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that:

1. The temperature of the sodium pentaborate solution is within the limits of Figure 3.1.5-1.

2. The available volume of sodium pentaborate solution is at least 3160 gallons.

3. The temperature of the pump suction piping is within the limits of Figure 3.1.5-1 for the most recent concentration analysis.

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

, or in accordance with the Risk Informed Completion Time Program,

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

Note: Separate condition entry is allowed for each channel.

a. With the number of OPERABLE channels in either trip system for one or more Functional Units less than the Minimum OPERABLE Channels per Trip System required by Table 3.3.1-1, within one hour for each affected functional unit either verify that at least one* channel in each trip system is OPERABLE or tripped or that the trip system is tripped, or place either the affected trip system or at least one inoperable channel in the affected trip system in the tripped condition.

b. With the number of OPERABLE channels in either trip system less than the Minimum OPERABLE Channels per Trip System required by Table 3.3.1-1, place either the inoperable channel(s) or the affected trip system** in the tripped condition within 12 hours.

c. With the number of OPERABLE channels in both trip systems for one or more Functional Units less than the Minimum OPERABLE Channels per Trip System required by Table 3.3.1-1, place either the inoperable channel(s) in one trip system or one trip system in the tripped condition within 6 hours**.

d. If within the allowable time allocated by Actions a, b or c, it is not desired to place the inoperable channel or trip system in trip (e.g., full scram would occur), Then no later than expiration of that allowable time initiate the action identified in Table 3.3.1-1 for the applicable Functional Unit.

, or in accordance with the Risk Informed Completion Time Program

, or in accordance with the Risk Informed Completion Time Program.***

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* For Functional Units 2.a, 2.b, 2.c, 2.d, and 2.f, at least two channels shall be OPERABLE or tripped. For Functional Unit 5, both trip systems shall have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or tripped. For Function 9, at least three channels per trip system shall be OPERABLE or tripped.

** For Functional Units 2.a, 2.b, 2.c, 2.d, and 2.f, inoperable channels shall be placed in the tripped condition to comply with Action b. Action c does not apply for these Functional Units.

*** Not applicable when trip capability is not maintained for one or more Functional Units.

3/4.3.2. ISOLATION ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The isolation actuation instrumentation channels shown in Table 3.3.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.2.-2 and with ISOLATION SYSTEM RESPONSE TIME as shown in Table 3.3.2-3.

APPLICABILITY: As shown in Table 3.3.2-1.

ACTION:

a) With an isolation actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b) With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirements for one trip system:

1. If placing the inoperable channel(s) in the tripped condition would cause an isolation, the inoperable channel(s) shall be restored to OPERABLE status within 6 hours or in accordance with the Risk Informed Completion Time Program. If this cannot be accomplished, the ACTION required by Table 3.3.2-1 for the affected trip function shall be taken, or the channel shall be placed in the tripped condition.

or

2. If placing the inoperable channel(s) in the tripped condition would not cause an isolation, the inoperable channel(s) and/or that trip system shall be placed in the tripped condition within:

   a) 12 hours or in accordance with the Risk Informed Completion Time Program for trip functions common* to RPS Instrumentation,

   b) 24 hours or in accordance with the Risk Informed Completion Time Program for trip functions not common* to RPS Instrumentation.

* Trip functions common to RPS Actuation Instrumentation are shown in Table 4.3.2.1-1.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2 and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.

APPLICABILITY: As shown in Table 3.3.3-1

ACTION:

a. With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, declare the channel inoperable until the channel is restored to Operable status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.3-1.

c. With either ADS trip system subsystem inoperable, restore the inoperable trip system to OPERABLE status within:

   1. 7 days, provided that the HPCI and RCIC systems are OPERABLE.
   2. 72 hours. or in accordance with the Risk Informed Completion Time Program

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 100 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS shown in Table 4.3.3.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.3.1-1.

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shown in Table 3.3.3-3 shall be demonstrated to be within the limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times the frequency specified in the Surveillance Frequency Control Program where N is the total number of redundant channels in a specific ECCS trip system.

TABLE 3.3.3-1 (Continued)
EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION
ACTION STATEMENTS

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

a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or declare the associated system inoperable.

b. With more than one channel inoperable, declare the associated system inoperable.

ACTION 31 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, declare the associated ECCS inoperable within 24 hours.

ACTION 32 - DELETED

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 24 hours or declare the associated ECCS inoperable.

ACTION 34 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. For one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or declare the HPCI system inoperable.

b. With more than one channel inoperable, declare the HPCI system inoperable.

ACTION 35 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within 24 hours or declare the HPCI system inoperable.

ACTION 36 - With the number of OPERABLE channels less than the Total Number of Channels, declare the associated emergency diesel generator and the associated offsite source breaker that is not supplying the bus inoperable and take the ACTION required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

or in accordance with the Risk Informed Completion Time Program,

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.1 The anticipated transient without scram recirculation pump trip (ATWS-RPT) system instrumentation channels shown in Table 3.3.4.1-1 shall be OPERABLE with their trip setpoints set consistent with values shown in the Trip Setpoint column of Table 3.3.4.1-2.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION:

a. With an ATWS recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.1-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 24 hours, or in accordance with the Risk Informed Completion Time Program*.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

1. If the inoperable channels consist of one reactor vessel water level channel and one reactor vessel pressure channel, place both inoperable channels in the tripped condition within 24 hours, or in accordance with the Risk Informed Completion Time Program*, or, if this action will initiate a pump trip, declare the trip system inoperable.

2. If the inoperable channels include two reactor vessel water level channels or two reactor vessel pressure channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours, or in accordance with the Risk Informed Completion Time Program, or be in at least STARTUP within the next 6 hours.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.1.1 Each of the required ATWS recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.4.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

* Not applicable when trip capability is not maintained.

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 29.5% of RATED THERMAL POWER.

, or in accordance with the Risk Informed Completion Time Program*

ACTION:

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

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 12 hours.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

   1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within 12 hours.

   2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or take the ACTION required by Specification 3.2.3.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or take the ACTION required by Specification 3.2.3.

, or in accordance with the Risk Informed Completion Time Program,

* Not applicable when trip capability is not maintained.

TABLE 3.3.5-1 (Continued)

REACTOR CORE ISOLATION COOLING SYSTEM
ACTION STATEMENTS

ACTION 50 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or declare the RCIC system inoperable.

b. With more than one channel inoperable, declare the RCIC system inoperable.

ACTION 51 - With the number of OPERABLE channels less than required by the minimum OPERABLE channels per Trip System requirement, declare the RCIC system inoperable within 24 hours.

ACTION 52 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place at least one inoperable channel in the tripped condition within 24 hours or declare the RCIC system inoperable.

ACTION 53 - With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the inoperable channel to OPERABLE status within 24 hours or declare the RCIC system inoperable.

, or in accordance with the Risk Informed Completion Time Program,

INSTRUMENTATION

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.9 The feedwater/main turbine trip system actuation instrumentation channels shown in the Table 3.3.9-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.9-2.

APPLICABILITY: As shown in Table 3.3.9-1.

ACTION:

a. With a feedwater/main turbine trip system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.9-2, declare the channel inoperable and either place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value, or declare the associated system inoperable.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 7 days, or in accordance with the Risk Informed Completion Time Program, or be in at least STARTUP within the next 6 hours.

c. With the number of OPERABLE channels two less than required by the Minimum OPERABLE Channels requirement, restore at least one of the inoperable channels to OPERABLE status within 72 hours, or in accordance with the Risk Informed Completion Time Program**, or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.9.1 Each of the required feedwater/main turbine trip system actuation instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.9.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition.

** Not applicable when trip capability is not maintained.

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.4.7 Two main steam line isolation valves (MSIVs) per main steam line shall be OPERABLE with closing times greater than or equal to 3 and less than or equal to 5 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

or in accordance with the Risk Informed Completion Time Program

With one or more MSIVs inoperable:

a. Maintain at least one MSIV OPERABLE in each affected main steam line that is open and within 8 hours, either:

   1. Restore the inoperable valve(s) to OPERABLE status, or

   2. Isolate the affected main steam line by use of a deactivated MSIV in the closed position.

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

SURVEILLANCE REQUIREMENTS

4.4.7 Each of the above required MSIVs shall be demonstrated OPERABLE by verifying full closure between 3 and 5 seconds when tested pursuant to Specification 4.0.5.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION:

a. For the core spray system:

or in accordance with the Risk Informed Completion Time Program,

1. With one CSS subsystem inoperable, provided that at least two LPCI subsystems are OPERABLE, restore the inoperable CSS subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With both CSS subsystems inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. For the LPCI system:

1. With one LPCI subsystem inoperable, provided that at least one CSS subsystem is OPERABLE, restore the inoperable LPCI pump to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one RHR cross-tie valve (HV-51-282 A or B) open, or power not removed from one closed RHR cross-tie valve operator, close the open valve and/or remove power from the closed valves operator within 72 hours, or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

3. With no RHR cross-tie valves (HV-51-282 A, B) closed, or power not removed from both closed RHR cross-tie valve operators, or with one RHR cross-tie valve open and power not removed from the other RHR cross-tie valve operator, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

4. With two LPCI subsystems inoperable, provided that at least one CSS subsystem is OPERABLE, restore at least three LPCI subsystems to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

5. With three LPCI subsystems inoperable, provided that both CSS subsystems are OPERABLE, restore at least two LPCI subsystems to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

6. With all four LPCI subsystems inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.*

or in accordance with the Risk Informed Completion Time Program,

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

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued) or in accordance with the Risk Informed Completion Time Program,

c. For the HPCI system:

1. With the HPCI system inoperable, provided the CSS, the LPCI system, the ADS and the RCIC system are OPERABLE, restore the HPCI system to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 200 psig within the following 24 hours.

2. With the HPCI system inoperable, and one CSS subsystem, and/or LPCI subsystem inoperable, and provided at least one CSS subsystem, three LPCI subsystems, and ADS are operable, restore the HPCI to OPERABLE within 8 hours, or be in HOT SHUTDOWN in the next 12 hours, and in COLD SHUTDOWN in the next 24 hours.

3. Specification 3.0.4.b is not applicable to HPCI.

d. For the ADS:

1. With one of the above required ADS valves inoperable, provided the HPCI system, the CSS and the LPCI system are OPERABLE, restore the inoperable ADS valve to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

2. With two or more of the above required ADS valves inoperable, be in at least HOT SHUTDOWN within 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

e. With a CSS and/or LPCI header ΔP instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 72 hours or determine the ECCS header ΔP locally at least once per 12 hours; otherwise, declare the associated CSS and/or LPCI, as applicable, inoperable.

f. DELETED

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT AIR LOCK

LIMITING CONDITION FOR OPERATION

3.6.1.3 The primary containment air lock shall be OPERABLE with:

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

b. An overall air lock leakage rate in accordance with the Primary Containment Leakage Rate Testing Program.

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

ACTION:

a. With one primary containment air lock door inoperable:

1. Maintain at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours or in accordance with the Risk Informed Completion Time Program, or lock the OPERABLE air lock door closed.

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

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

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

*See Special Test Exception 3.10.1.

CONTAINMENT SYSTEMS

SUPPRESSION POOL SPRAY

LIMITING CONDITION FOR OPERATION

3.6.2.2 The suppression pool spray mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHR heat exchanger and the suppression pool spray sparger(s).

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

or in accordance with the Risk Informed Completion Time Program,

a. With one suppression pool spray loop inoperable, restore the inoperable loop to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool spray loops inoperable, restore at least one loop to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The suppression pool spray mode of the RHR system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of at least 500 gpm on recirculation flow through the RHR heat exchanger and the suppression pool spray sparger when tested pursuant to Specification 4.0.5.

c. By verifying RHR suppression pool spray subsystem locations susceptible to gas accumulation are sufficiently filled with water in accordance with the Surveillance Frequency Control Program.

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

CONTAINMENT SYSTEMS

SUPPRESSION POOL COOLING

LIMITING CONDITION FOR OPERATION

3.6.2.3 The suppression pool cooling mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one suppression pool cooling loop inoperable, restore the inoperable loop to OPERABLE status within 72 hours** or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool cooling loops inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN* within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.3 The suppression pool cooling mode of the RHR system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of at least 10,000 gpm on recirculation flow through the flow path including the RHR heat exchanger and its associated closed bypass valve, the suppression pool and the full flow test line when tested pursuant to Specification 4.0.5.

c. By verifying RHR suppression pool cooling subsystem locations susceptible to gas accumulation are sufficiently filled with water in accordance with the Surveillance Frequency Control Program.

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

**During the extended 7-day Allowed Outage Time (AOT) specified by TS LCO 3.7.1.1, Action a.3.a) or a.3.b) to allow for RHRSW subsystem piping repairs, the 72-hour AOT for one inoperable suppression pool cooling loop may also be extended to 7 days or in accordance with the Risk Informed Completion Time Program for the same 7 day period.

CONTAINMENT SYSTEMS

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3 Each primary containment isolation valve and each instrumentation line excess flow check valve shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

, or in accordance with the Risk Informed Completion Time Program,

a. With one or more of the primary containment isolation valves inoperable,** maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 4 hours either:

1. Restore the inoperable valve(s) to OPERABLE status, or

2. Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position,* or

3. Isolate each affected penetration by use of at least one closed manual valve or blind flange.*

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

b. With one or more of the instrumentation line excess flow check valves inoperable, operation may continue and the provisions of Specification 3.0.3 are not applicable provided that within 4 hours either:

1. The inoperable valve is returned to OPERABLE status, or

2. The instrument line is isolated and the associated instrument is declared inoperable.

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

c. With one or more scram discharge volume vent or drain valves inoperable, perform the applicable actions specified in Specification 3.1.3.1.

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* Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.

** Except for the scram discharge volume vent and drain valves.

3/4.6.4 VACUUM RELIEF

SUPPRESSION CHAMBER - DRYWELL VACUUM BREAKERS

LIMITING CONDITION FOR OPERATION

3.6.4.1 Three pairs of suppression chamber - drywell vacuum breakers shall be OPERABLE and all suppression chamber - drywell vacuum breakers shall be closed.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

or in accordance with the Risk Informed Completion Time Program,

a. With one or more vacuum breakers in one of the three required pairs of suppression chamber - drywell vacuum breaker pairs inoperable for opening but known to be closed, restore at least one inoperable pair of vacuum breakers to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one suppression chamber - drywell vacuum breaker open, verify the other vacuum breaker in the pair to be closed within 2 hours; restore the open vacuum breaker to the closed position within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With one position indicator of any suppression chamber - drywell vacuum breaker inoperable:

1. Verify the other vacuum breaker in the pair to be closed within 2 hours and at least once per 15 days thereafter, or

2. Verify the vacuum breaker(s) with the inoperable position indicator to be closed by conducting a test which demonstrates that the ΔP is maintained at greater than or equal to 0.7 psi for one hour without makeup within 24 hours and at least once per 15 days thereafter.

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

STANDBY GAS TREATMENT SYSTEM - COMMON SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.3 Two independent standby gas treatment subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, and when (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS.

or in accordance with the Risk Informed Completion Time Program,

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3:

1. With the Unit 1 diesel generator for one standby gas treatment subsystem inoperable for more than 30 days, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one standby gas treatment subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. With one standby gas treatment subsystem inoperable and the other standby gas treatment subsystem with an inoperable Unit 1 diesel generator, restore the inoperable subsystem to OPERABLE status or restore the inoperable Unit 1 diesel generator to OPERABLE status within 72 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4. With the Unit 1 diesel generators for both standby gas treatment system subsystems inoperable for more than 72 hours, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. When (1) irradiated fuel is being handled in the refueling area secondary containment, or (2) during CORE ALTERATIONS:

1. With one standby gas treatment subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or suspend handling of irradiated fuel in the secondary containment and CORE ALTERATIONS. The provisions of Specification 3.0.3 are not applicable.

2. With both standby gas treatment subsystems inoperable, if in progress, suspend handling of irradiated fuel in the secondary containment and CORE ALTERATIONS. The provisions of Specification 3.0.3 are not applicable.

RESIDUAL HEAT REMOVAL SERVICE WATER SYSTEM - COMMON SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.1 At least the following independent residual heat removal service water (RHRSW) system subsystems, with each subsystem comprised of:

a. Two OPERABLE RHRSW pumps, and

b. An OPERABLE flow path capable of taking suction from the RHR service water pumps wet pits which are supplied from the spray pond or the cooling tower basin and transferring the water through one Unit 2 RHR heat exchanger,

shall be OPERABLE:

a. In OPERATIONAL CONDITIONS 1, 2, and 3, two subsystems.

b. In OPERATIONAL CONDITIONS 4 and 5, the subsystem(s) associated with systems and components required OPERABLE by Specification 3.4.9.2, 3.9.11.1, and 3.9.11.2.

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

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3:

1. With one RHRSW pump inoperable, restore the inoperable pump to OPERABLE status within 30 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

or in accordance with the Risk Informed Completion Time Program,

2. With one RHRSW pump in each subsystem inoperable, restore at least one of the inoperable RHRSW pumps to OPERABLE status within 7 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. With one RHRSW subsystem otherwise inoperable, restore the inoperable subsystem to OPERABLE status with at least one OPERABLE RHRSW pump within 72 hours, unless otherwise specified in a) or b) below**, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

a) When the 'A' RHRSW subsystem is inoperable to allow for repairs of the 'A' RHRSW subsystem piping, with Limerick Generating Station Unit 1 shutdown, reactor vessel head removed and reactor cavity flooded, the 72-hour Allowed Outage Time may be extended to 7 days once every other calendar year with the following compensatory measures established:

or in accordance with the Risk Informed Completion Time Program

** Only one of these two Actions, either a.3.a) or a.3.b), may be entered on Unit 2 in a calendar year. However, if either Unit 1 TS LCO 3.7.1.1, Action a.3.a) or a.3.b) has previously been entered in the calendar year, then Unit 2 Action a.3.a) or a.3.b) may not be entered during that same calendar year.

ACTION: (Continued)

1) The following systems and subsystems will be protected in accordance with applicable station procedures:
   - 'B' RHRSW subsystem
   - 'B' ESW loop
   - 'B' and 'D' RHR subsystems
   - D12, D22, and D24 4kV buses and emergency diesel generators
   - Division 2 and Division 4 Safeguard DC, and

2) The 'A' and 'B' loop of ESW return flow shall be aligned to the operable 'B' RHRSW return header only. The ESW return valves to the 'B' RHRSW return header (i.e., HV-11-015A and HV-11-015B) will be administratively controlled in the open position and de-energized prior to entering the extended AOT. The ESW return valves to the 'A' RHRSW return header (i.e., HV-11-011A and HV-11-011B) will be administratively controlled in the closed position and de-energized as part of the work boundary.

or in accordance with the Risk Informed Completion Time Program

b) When the 'B' RHRSW subsystem is inoperable to allow for repairs of the 'B' RHRSW subsystem piping, with Limerick Generating Station Unit 1 shutdown, reactor vessel head removed and reactor cavity flooded, the 72-hour Allowed Outage Time may be extended to 7 days once every other calendar year with the following compensatory measures established:

1) The following systems and subsystems will be protected in accordance with applicable station procedures:
   - 'A' RHRSW subsystem
   - 'A' ESW loop
   - 'A' and 'C' RHR subsystems
   - D11, D21, and D23 4kV buses and emergency diesel generators
   - Division 1 and Division 3 Safeguard DC, and

2) The 'A' and 'B' loop of ESW return flow shall be aligned to the operable 'A' RHRSW return header only. The ESW return valves to the 'A' RHRSW return header (i.e., HV-11-011A and HV-11-011B) will be administratively controlled in the open position and de-energized prior to entering the extended AOT. The ESW return valves to the 'B' RHRSW return header (i.e., HV-11-015A and HV-11-015B) will be administratively controlled in the closed position and de-energized as part of the work boundary.

4. With both RHRSW subsystems otherwise inoperable, restore at least one subsystem to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* within the following 24 hours.

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

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

5. With two RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

or in accordance with the Risk Informed Completion Time Program

6. With three RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

7. With four RHRSW pump/diesel generator pairs* inoperable, restore at least one inoperable RHRSW pump/diesel generator pair* to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 3 or 4 with the RHRSW subsystem(s), which is associated with an RHR loop required OPERABLE by Specification 3.4.9.1 or 3.4.9.2, inoperable, declare the associated RHR loop inoperable and take the ACTION required by Specification 3.4.9.1 or 3.4.9.2, as applicable.

c. In OPERATIONAL CONDITION 5 with the RHRSW subsystem(s), which is associated with an RHR loop required OPERABLE by Specification 3.9.11.1 or 3.9.11.2, inoperable, declare the associated RHR system inoperable and take the ACTION required by Specification 3.9.11.1 or 3.9.11.2, as applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 At least the above required residual heat removal service water system subsystem(s) shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that each valve in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

*A RHRSW pump/diesel generator pair consists of a RHRSW pump and its associated diesel generator. If either a RHRSW pump or its associated diesel generator becomes inoperable, then the RHRSW pump/diesel generator pair is inoperable.

3.7.1.2 At least the following independent emergency service water system loops, with each loop comprised of:

a. Two OPERABLE emergency service water pumps, and

b. An OPERABLE flow path capable of taking suction from the emergency service water pumps wet pits which are supplied from the spray pond or the cooling tower basin and transferring the water to the associated Unit 2 and common safety-related equipment,

shall be OPERABLE:

a. In OPERATIONAL CONDITIONS 1, 2, and 3, two loops.

b. In OPERATIONAL CONDITIONS 4, 5, and *, one loop.

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

ACTION:

a. In OPERATION CONDITION 1, 2, or 3:

1. With one emergency service water pump inoperable, restore the inoperable pump to OPERABLE status within 45 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one emergency service water pump in each loop inoperable, restore at least one inoperable pump to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. With one emergency service water system loop otherwise inoperable, declare all equipment aligned to the inoperable loop inoperable**, restore the inoperable loop to OPERABLE status with at least one OPERABLE pump within 72 hours# or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

*When handling irradiated fuel in the secondary containment.

**The diesel generators may be aligned to the OPERABLE emergency service water system loop provided confirmatory flow testing has been performed. Those diesel generators not aligned to the OPERABLE emergency service water system loop shall be declared inoperable and the actions of 3.8.1.1 taken.

#During the extended ~~7 day~~ Allowed Outage Time (AOT) specified by TS LCO 3.7.1.1, Action a.3.a) or a.3.b) to allow for RHRSW subsystem piping repairs, the 72-hour AOT for one inoperable emergency service water system loop may also be extended to 7 days or in accordance with the Risk Informed Completion Time Program for the same ~~7 day~~ period.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

4. With three ESW pump/diesel generator pairs** inoperable, restore at least one inoperable ESW pump/diesel generator pair** to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

5. With four ESW pump/diesel generator pairs** inoperable, restore at least one inoperable ESW pump/diesel generator pair** to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4 or 5:

1. With only one emergency service water pump and its associated flow path OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or declare the associated safety related equipment inoperable and take the ACTION required by Specifications 3.5.2 and 3.8.1.2.

c. In OPERATIONAL CONDITION *

1. With only one emergency service water pump and its associated flow path OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or verify adequate cooling remains available for the diesel generators required to be OPERABLE or declare the associated diesel generator(s) inoperable and take the ACTION required by Specification 3.8.1.2. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENT

4.7.1.2 At least the above required emergency service water system loop(s) shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by verifying that each valve (manual, power-operated, or automatic) that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. In accordance with the Surveillance Frequency Control Program by verifying that:

1. Each automatic valve actuates to its correct position on its appropriate ESW pump start signal.

2. Each pump starts automatically when its associated diesel generator starts.

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* When handling irradiated fuel in the secondary containment.

** An ESW pump/diesel generator pair consists of an ESW pump and its associated diesel generator. If either an ESW pump or its associated diesel generator becomes inoperable, than the ESW pump/diesel generator pair is inoperable.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 The reactor core isolation cooling (RCIC) system shall be OPERABLE with an OPERABLE flow path capable of automatically taking suction from the suppression pool and transferring the water to the reactor pressure vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 with reactor steam dome pressure greater than 150 psig.

ACTION:

or in accordance with the Risk Informed Completion Time Program

a. With the RCIC system inoperable, operation may continue provided the HPCI system is OPERABLE; restore the RCIC system to OPERABLE status within 14 days. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 150 psig within the following 24 hours.

b. DELETED

c. Specification 3.0.4.b is not applicable to RCIC.

SURVEILLANCE REQUIREMENTS

4.7.3 The RCIC system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by:

1. Verifying locations susceptible to gas accumulation are sufficiently filled with water.

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

3. Verifying that the pump flow controller is in the correct position.

b. In accordance with the Surveillance Frequency Control Program by verifying that the RCIC pump develops a flow of greater than or equal to 600 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 1040 + 13, - 120 psig.*

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* The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 150 psig within the following 72 hours.

** Not required to be met for system vent flow paths opened under administrative control.

3/4.7.8 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.8 The main turbine bypass system shall be OPERABLE as determined by the number of operable main turbine bypass valves being greater than or equal to that specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 1 hour or in accordance with the Risk Informed Completion Time Program, or take the ACTION required by Specification 3.2.3.c.

SURVEILLANCE REQUIREMENTS

4.7.8 The main turbine bypass system shall be demonstrated OPERABLE in accordance with the Surveillance Frequency Control Program:

a. By cycling each turbine bypass valve through at least one complete cycle of full travel,

b. By performing a system functional test which includes simulated automatic actuation, and by verifying that each automatic valve actuates to its correct position, and

c. By determining TURBINE BYPASS SYSTEM RESPONSE TIME to be less than or equal to the value specified in the CORE OPERATING LIMITS REPORT.

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Four separate and independent diesel generators, each with:

   1. A separate day tank containing a minimum of 250 gallons of fuel,

   2. A separate fuel storage system containing a minimum of 33,500 gallons of fuel, and

   3. A separate fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 24 hours and at least once per 7 days thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining operable diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 24 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore the inoperable diesel generator to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

b. With two diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If either of the diesel generators became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 8 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore at least one of the inoperable diesel generators to OPERABLE status within 72 hours* or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

*During the extended ~~7-day~~ Allowed Outage Time (AOT) specified by TS LCO 3.7.1.1, Action a.3.a) or a.3.b) to allow for RHRSW subsystem piping repairs, the 72-hour AOT for two inoperable diesel generators may also be extended to 7 days or in accordance with the Risk Informed Completion Time Program for the same ~~7-day~~ period.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With three diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and perform Surveillance Requirement 4.8.1.1.2.a.4 for the remaining diesel generator, within 1 hour. Restore at least one of the inoperable diesel generators to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

d. With one offsite circuit and one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 8 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

, or in accordance with the Risk Informed Completion Time Program,

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

e. In addition to the ACTIONS above:

1. For two train systems, with one or more diesel generators of the above required A.C. electrical power sources inoperable, verify within 2 hours and at least once per 12 hours thereafter that at least one of the required two train system subsystem, train, components, and devices is OPERABLE and its associated diesel generator is OPERABLE. Otherwise, restore either the inoperable diesel generator or the inoperable system subsystem to an OPERABLE status within 72 hours* or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. For the LPCI systems, with two or more diesel generators of the above required A.C. electrical power sources inoperable, verify within 2 hours and at least once per 12 hours thereafter that at least two of the required LPCI system subsystems, trains, components and devices are OPERABLE and its associated diesel generator is OPERABLE. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

This ACTION does not apply for those systems covered in Specifications 3.7.1.1 and 3.7.1.2.

or in accordance with the Risk Informed Completion Time Program,

*During the extended ~~7 day~~ Allowed Outage Time (AOT) specified by TS LCO 3.7.1.1, Action a.3.a) or a.3.b) to allow for RHRSW subsystem piping repairs, the 72-hour AOT may also be extended to 7 days for the same ~~7 day~~ period.

or in accordance with the Risk Informed Completion Time Program

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

f. With one offsite circuit of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore at least two offsite circuits to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

g. With two of the above required offsite circuits inoperable, restore at least one of the inoperable offsite circuits to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours. With only one offsite circuit restored to OPERABLE status, restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

h. With one offsite circuit and two diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If either of the diesel generators became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 for one diesel generator at a time, within 8 hours, unless the absence of any potential common-mode failure for the remaining diesel generators is determined. Restore at least one of the above required inoperable A.C. sources to OPERABLE status within 12 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore at least two offsite circuits and at least three of the above required diesel generators to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. See also ACTION e.

i. Specification 3.0.4.b is not applicable to diesel generators.

, or in accordance with the Risk Informed Completion Time Program,

ELECTRICAL POWER SYSTEMS

3/4.8.2 D.C. SOURCES

D.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 As a minimum, the following D.C. electrical power sources shall be OPERABLE:

a. Division 1, Consisting of:
   1. 125-Volt Battery 2A1 (2A1D101).
   2. 125-Volt Battery 2A2 (2A2D101).
   3. 125-Volt Battery Charger 2BCA1 (2A1D103).
   4. 125-Volt Battery Charger 2BCA2 (2A2D103).

b. Division 2, Consisting of:
   1. 125-Volt Battery 2B1 (2B1D101).
   2. 125-Volt Battery 2B2 (2B2D101).
   3. 125-Volt Battery Charger 2BCB1 (2B1D103).
   4. 125-Volt Battery Charger 2BCB2 (2B2D103).

c. Division 3, Consisting of:
   1. 125-Volt Battery 2C (2CD101).
   2. 125-Volt Battery Charger 2BCC (2CD103).

d. Division 4, Consisting of:
   1. 125-Volt Battery 2D (2DD101).
   2. 125-Volt Battery Charger 2BCD (2DD103).

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION: , or in accordance with the Risk Informed Completion Time Program

a. With one or two battery chargers on one division inoperable:

   1. Restore battery terminal voltage to greater than or equal to the minimum established float voltage within 2 hours,

   2. Verify associated Division 1 or 2 float current ≤ 2 amps, or Division 3 or 4 float current ≤ 1 amp within 18 hours and once per 12 hours thereafter, and

   3. Restore battery charger(s) to OPERABLE status within 7 days.

b. With one or more batteries inoperable due to:

   1. One or two batteries on one division with one or more battery cells float voltage < 2.07 volts, perform 4.8.2.1.a.1 and 4.8.2.1.a.2 within 2 hours for affected battery(s) and restore affected cell(s) voltage ≥ 2.07 volts within 24 hours.

   2. Division 1 or 2 with float current > 2 amps, or with Division 3 or 4 with float current > 1 amp, perform 4.8.2.1.a.2 within 2 hours for affected battery(s) and restore battery float current to within limits within 18 hours.

LIMITING CONDITION FOR OPERATION

ACTION: (Continued)

3. One or two batteries on one division with one or more cells electrolyte level less than minimum established design limits, if electrolyte level was below the top of the plates restore electrolyte level to above top of plates within 8 hours and verify no evidence of leakage(*) within 12 hours. In all cases, restore electrolyte level to greater than or equal to minimum established design limits within 31 days.

4. One or two batteries on one division with pilot cell electrolyte temperature less than minimum established design limits, restore battery pilot cell temperature to greater than or equal to minimum established design limits within 12 hours.

5. Batteries in more than one division affected, restore battery parameters for all batteries in all but one division to within limits within 2 hours.

6. (i) Any battery having both (Action b.1) one or more battery cells float voltage < 2.07 volts and (Action b.2) float current not within limits, and/or

   (ii) Any battery not meeting any Action b.1 through b.5,

   Restore the battery parameters to within limits within 2 hours.

c. With any battery(ies) on one division of the above required D.C. electrical power sources inoperable for reasons other than Action b., restore the inoperable division battery to OPERABLE status within 2 hours~~.~~

, or in accordance with the Risk Informed Completion Time Program

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

(*) Contrary to the provisions of Specification 3.0.2, if electrolyte level was below the top of the plates, the verification that there is no evidence of leakage is required to be completed regardless of when electrolyte level is restored.

LIMITING CONDITION FOR OPERATION (Continued)

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

or in accordance with the Risk Informed Completion Time Program,

ACTION:

a. With one of the above required Unit 2 A.C. distribution system divisions not energized, reenergize the division within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one of the above required Unit 2 D.C. distribution system divisions not energized, reenergize the division within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any of the above required Unit 1 and common AC and/or DC distribution system divisions not energized, declare the associated common equipment inoperable, and take the appropriate ACTION for that system.

SURVEILLANCE REQUIREMENTS

4.8.3.1 Each of the above required power distribution system divisions shall be determined energized in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignment and voltage on the busses/MCCs/panels.

c. The program shall, as allowed by 10 CFR 50.55a, meet Subsection ISTA, "General Requirements," and Subsection ISTD, "Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants," in lieu of Section XI of the ASME B&PV Code ISI requirements for snubbers, or meet authorized alternatives pursuant to 10 CFR 50.55a.

d. The 120-month program updates shall be made in accordance with 10 CFR 50.55a subject to the limitations and conditions listed therein.

l. Explosive Gas Monitoring Program

This program provides controls for potentially explosive gas mixtures contained downstream of the off-gas recombiners.

The program shall include:

a. The limit for the concentration of hydrogen downstream of the offgas recombiners and a surveillance program to ensure the limit is maintained. This limit shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

The provisions of SR 4.0.2 and SR 4.0.3 are applicable to the Explosive Gas Monitoring Program surveillance frequencies.

Insert

LGS TS MARKUP INSERT

LGS TS 6.8.4.m

INSERT

m. 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 OPERATIONAL CONDITIONs 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 ACTION allowed outage 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 ACTION allowed outage time, the RICT shall account for the increased possibility of common cause failure (CCF) by either:

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

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

e. The risk assessment approaches and methods shall be acceptable to the NRC. The plant PRA shall be based on the as-built, as-operated, and maintained plant; and reflect the operating experience at the plant, as specified in Regulatory Guide 1.200, Revision 2. Methods to assess the risk from extending the completion times must be PRA methods approved for use with this program in Amendment Nos. [XXX/YYY], 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.

ATTACHMENT 3

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

<u>Proposed Technical Specification Bases Changes (Mark-Ups)</u>

<u>TS Bases Pages</u>

B 3/4 3-1a
B 3/4 3-1b
B 3/4 5-2
B 3/4 5-3
B 3/4 7-1
B 3/4 7-1c
B 3/4 8-1d

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Action b, so the voter Function 2.e must be declared inoperable if any of its functionality is inoperable. The voter Function 2.e does not need to be declared inoperable due to any failure affecting only the APRM Interface hardware portion of the Two-Out-Of-Four Logic Module.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. To provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. In addition, no more than 9 LPRMs may be bypassed between APRM calibrations (weekly gain adjustments). For the OPRM Upscale Function 2.f, LPRMs are assigned to "cells" of 3 or 4 detectors. A minimum of 23 cells (Reference 9), each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for each APRM channel for the OPRM Upscale Function 2.f to be OPERABLE in that channel. LPRM gain settings are determined from the local flux profiles measured by the TIP system. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 2000 EFPH frequency is based on operating experience with LPRM sensitivity changes.

References 4, 5 and 6 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in any cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is at ≥ 25% RATED THERMAL POWER. The 25% RATED THERMAL POWER level is selected to provide margin in the unlikely event that a reactor power increase transient occurring while the plant is operating below 29.5% RATED THERMAL POWER causes a power increase to or beyond the 29.5% RATED THERMAL POWER OPRM Upscale trip auto-enable point without operator action. This OPERABILITY requirement assures that the OPRM Upscale trip automatic-enable function will be OPERABLE when required.

Actions a, b and c define the Action(s) required when RPS channels are discovered to be inoperable. For those Actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for Actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability. Alternatively, an allowable out of service time can be determined in accordance with the Risk Informed Completion Time Program.

Alternatively, the completion time can be determined in accordance with the Risk Informed Completion Time Program.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action a are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic, including the IRM Functions and APRM Function 2.e (trip capability associated with APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f are discussed below), this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 9 (Turbine Stop Valve-Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The completion time to satisfy the requirements of Action a is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

With trip capability maintained, i.e., Action a satisfied, Actions b and c as applicable must still be satisfied. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Action b requires that the channel or the associated trip system must be placed in the tripped condition. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

As noted, placing the trip system in trip is not applicable to satisfy Action b for APRM functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, the Action b requirements can only be satisfied by placing the inoperable APRM channel in trip. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and the requirement to satisfy Action a.

The requirements of Action c must be satisfied when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, normally the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system (see additional bases discussion above related to loss of trip capability and the requirements of Action a, and special cases for Functions 2.a, 2.b, 2.c, 2.d, 2.f, 5 and 9).

Alternatively, the out-of-service times described above can be determined in accordance with the Risk Informed Completion Time Program.

ECCS - OPERATING (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown.

The ECCS injection/spray subsystem flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS injection/spray subsystems and may also prevent a water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of ECCS injection/spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS injection/spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits. ECCS injection/spray

ECCS - OPERATING (Continued)

subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.5.1.a.1.b is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety/relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS subsystem out-of-service time allowances. Alternatively, the allowed out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

Verification that ADS accumulator gas supply header pressure is ≥90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥90 psig is provided by the PCIG supply.

3/4.7.1 SERVICE WATER SYSTEMS - COMMON SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

The RHR and ESW systems are common to Units 1 and 2 and consist of two independent subsystems each with two pumps. One pump per subsystem (loop) is powered from a Unit 1 safeguard bus and the other pump is powered from a Unit 2 safeguard bus. In order to ensure adequate onsite power sources to the systems during a loss of offsite power event, the inoperability of these supplies are restricted in system ACTION statements.

RHRSW is a manually operated system used for core and containment heat removal. Each of two RHRSW subsystems has one heat exchanger per unit. Each RHRSW pump provides adequate cooling for one RHR heat exchanger. By limiting operation with less than three OPERABLE RHRSW pumps with OPERABLE Diesel Generators, each unit is ensured adequate heat removal capability for the design scenario of LOCA/LOOP on one unit and simultaneous safe shutdown of the other unit.

Each ESW pump provides adequate flow to the cooling loads in its associated loop. With only two divisions of power required for LOCA mitigation of one unit and one division of power required for safe shutdown of the other unit, one ESW pump provides sufficient capacity to fulfill design requirements. ESW pumps are automatically started upon start of the associated Diesel Generators. Therefore, the allowable out of service times for OPERABLE ESW pumps and their associated Diesel Generators is limited to ensure adequate cooling during a loss of offsite power event.

Alternatively, the allowable out of service times can be determined in accordance with the Risk Informed Completion Time Program.

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

REFERENCES

1. UFSAR Section 6.4

2. UFSAR Section 9.5

3. Regulatory Guide 1.196

4. NEI 99-03, "Control Room Habitability Assessment Guidance, "June 2001.

5. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the emergency core cooling system equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure exceeds 150 psig. This pressure is substantially below that for which low pressure core cooling systems can provide adequate core cooling. Management of gas voids is important to RCIC System OPERABILITY.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2, and 3 when reactor vessel pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period. A Note prohibits the application of Specification 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable RCIC subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown.

Alternatively, the out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

3 or in accordance with the Risk Informed Completion Time Program

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 18 hours (Action a.2).

Action a.2 requires that the battery float current be verified for Divisions 1 and 2 as ≤ 2 amps, and for Divisions 3 and 4 as ≤ 1 amp. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 18 hour period the battery float current is not within limits this indicates there may be additional battery problems.

Action a.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 days reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

or the Risk Informed Completion Time

With one or more cells in one or more batteries in one division < 2.07 V, the battery cell is degraded. Per Action b.1, within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (4.8.2.1.a.2) and of the overall battery state of charge by monitoring the battery float charge current (4.8.2.1.a.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, with one or more cells in one or more batteries < 2.07 V, continued operation is permitted for a limited period up to 24 hours.

Division 1 or 2 with float current > 2 amps, or Division 3 or 4 with float current > 1 amp, indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Per Action b.2, within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage.

Since Actions b.1 and b.2 only specify "perform," a failure of 4.8.2.1.a.1 or 4.8.2.1.a.2 acceptance criteria does not result in this Action not being met. However, if one of the Surveillance Requirements is failed the appropriate Action(s), depending on the cause of the failures, is also entered.

If the Action b.2 condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 18 hours is a reasonable time prior to declaring the battery inoperable.

With one or more batteries in one division with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits(i.e., greater than minimum level indication mark), the b0ttery still retains sufficient capacity to perform the intended function. Per Action b.3, within 31 days the minimum established design limits for electrolyte level must be re-established.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Action b, so the voter Function 2.e must be declared inoperable if any of its functionality is inoperable. The voter Function 2.e does not need to be declared inoperable due to any failure affecting only the APRM Interface hardware portion of the Two-Out-Of-Four Logic Module.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. To provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. In addition, no more than 9 LPRMs may be bypassed between APRM calibrations (weekly gain adjustments). For the OPRM Upscale Function 2.f, LPRMs are assigned to "cells" of 3 or 4 detectors. A minimum of 23 cells (Reference 9), each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for each APRM channel for the OPRM Upscale Function 2.f to be OPERABLE in that channel. LPRM gain settings are determined from the local flux profiles measured by the TIP system. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 2000 EFPH frequency is based on operating experience with LPRM sensitivity changes.

References 4, 5 and 6 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in any cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is at ≥ 25% RATED THERMAL POWER. The 25% RATED THERMAL POWER level is selected to provide margin in the unlikely event that a reactor power increase transient occurring while the plant is operating below 29.5% RATED THERMAL POWER causes a power increase to or beyond the 29.5% RATED THERMAL POWER OPRM Upscale trip auto-enable point without operator action. This OPERABILITY requirement assures that the OPRM Upscale trip automatic-enable function will be OPERABLE when required.

Actions a, b and c define the Action(s) required when RPS channels are discovered to be inoperable. For those Actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for Actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability. Alternatively, an allowable out of service time can be determined in accordance with the Risk Informed Completion Time Program.

Alternatively, the completion time can be determined in accordance with the Risk Informed Completion Time Program

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action a are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic, including the IRM Functions and APRM Function 2.e (trip capability associated with APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f are discussed below), this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 9 (Turbine Stop Valve-Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The completion time to satisfy the requirements of Action a is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

With trip capability maintained, i.e., Action a satisfied, Actions b and c as applicable must still be satisfied. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Action b requires that the channel or the associated trip system must be placed in the tripped condition. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

As noted, placing the trip system in trip is not applicable to satisfy Action b for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, the Action b requirements can only be satisfied by placing the inoperable APRM channel in trip. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and the requirement to satisfy Action a.

The requirements of Action c must be satisfied when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, normally the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system (see additional bases discussion above related to loss of trip capability and the requirements of Action a, and special cases for Functions 2.a, 2.b, 2.c, 2.d, 2.f, 5 and 9).

Alternatively, the out-of-service times described above can be determined in accordance with the Risk Informed Completion Time Program.

ECCS - OPERATING (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown.

The ECCS injection/spray subsystem flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS injection/spray subsystems and may also prevent a water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of ECCS injection/spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS injection/spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

ECCS - OPERATING (Continued)

ECCS injection/spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.5.1.a.1.b is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety/relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS subsystem out-of-service time allowances.

Alternatively, the allowed out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

Verification that ADS accumulator gas supply header pressure is ≥90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥90 psig is provided by the PCIG supply.

Alternatively, the allowable out of service times can be determined in accordance with the Risk Informed Completion Time Program.

3/4.7.1 SERVICE WATER SYSTEMS - COMMON SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

The RHRSW and ESW systems are common to Units 1 and 2 and consist of two independent subsystems each with two pumps. One pump per subsystem (loop) is powered from a Unit 1 safeguard bus and the other pump is powered from a Unit 2 safeguard bus. In order to ensure adequate onsite power sources to the systems during a loss of offsite power event, the inoperability of these supplies are restricted in system ACTION statements.

RHRSW is a manually operated system used for core and containment heat removal. Each of two RHRSW subsystems has one heat exchanger per unit. Each RHRSW pump provides adequate cooling for one RHR heat exchanger. By limiting operation with less than three OPERABLE RHRSW pumps with OPERABLE Diesel Generators, each unit is ensured adequate heat removal capability for the design scenario of LOCA/LOOP on one unit and simultaneous safe shutdown of the other unit.

Each ESW pump provides adequate flow to the cooling loads in its associated loop. With only two divisions of power required for LOCA mitigation of one unit and one division of power required for safe shutdown of the other unit, one ESW pump provides sufficient capacity to fulfill design requirements. ESW pumps are automatically started upon start of the associated Diesel Generators. Therefore, the allowable out of service times for OPERABLE ESW pumps and their associated Diesel Generators is limited to ensure adequate cooling during a loss of offsite power event.

3/4.7.2 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM

The OPERABILITY of the control room emergency fresh air supply system ensures that the control room will remain habitable for occupants during and following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. Constant purge of the system at 1 cfm is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less Total Effective Dose Equivalent. This limitation is consistent with the requirements of 10 CFR Part 50.67, Accident Source Term.

Since the Control Room Emergency Fresh Air Supply System is not credited for filtration in OPERATIONAL CONDITIONS 4 and 5, applicability to 4 and 5 is only required to support the Chlorine and Toxic Gas design basis isolation requirements.

The CREFAS is common to Units 1 and 2 and consists of two independent subsystems. The power supplies for the system are from Unit 1 Safeguard busses, therefore, the inoperability of these Unit 1 supplies are addressed in the CREFAS ACTION statements in order to ensure adequate onsite power sources to CREFAS during a loss of offsite power event. The allowable out of service

CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

REFERENCES

1. UFSAR Section 6.4

2. UFSAR Section 9.5

3. Regulatory Guide 1.196

4. NEI 99-03, "Control Room Habitability Assessment Guidance," June 2001.

5. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the emergency core cooling system equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure exceeds 150 psig. This pressure is substantially below that for which low pressure core cooling systems can provide adequate core cooling. Management of gas voids is important to RCIC System OPERABILITY.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2, and 3 when reactor vessel pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period. Alternatively, the out-of-service time can be determined in accordance with the Risk Informed Completion Time Program. A Note prohibits the application of Specification 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable RCIC subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown.

, or in accordance with the Risk Informed Completion Time Program

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 18 hours (Action a.2).

Action a.2 requires that the battery float current be verified for Divisions 1 and 2 as ≤ 2 amps, and for Divisions 3 and 4 as ≤ 1 amp. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 18 hour period the battery float current is not within limits this indicates there may be additional battery problems.

Action a.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 days reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

, or the Risk Informed Completion Time,

With one or more cells in one or more batteries in one division < 2.07 V, the battery cell is degraded. Per Action b.1, within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (4.8.2.1.a.2) and of the overall battery state of charge by monitoring the battery float charge current (4.8.2.1.a.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, with one or more cells in one or more batteries < 2.07 V, continued operation is permitted for a limited period up to 24 hours.

Division 1 or 2 with float current > 2 amps, or Division 3 or 4 with float current > 1 amp, indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Per Action b.2, within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage.

Since Actions b.1 and b.2 only specify "perform," a failure of 4.8.2.1.a.1 or 4.8.2.1.a.2 acceptance criteria does not result in this Action not being met. However, if one of the Surveillance Requirements is failed the appropriate Action(s), depending on the cause of the failures, is also entered.

If the Action b.2 condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 18 hours is a reasonable time prior to declaring the battery inoperable.

With one or more batteries in one division with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, (i.e., greater than the minimum level indication mark), the battery still retains sufficient capacity to perform the intended function. Per Action b.3, within 31 days the minimum established design limits for electrolyte level must be re-established.

ATTACHMENT 4

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Cross-Reference of TSTF-505 and Limerick Generating Station Technical Specifications

Cross-Reference of TSTF-505 and Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
Completion Times	**1.3**	**---------**		
Example 1.3-8	1.3-8	---------		The LGS TS do not contain a section with examples. This example will not be added to the LGS TS.
Standby Liquid Control (SLC) System	**3.1.7**	**3.1.5**		
One SLC subsystem inoperable.	3.1.7.B	3.1.5.a	Yes	LGS TS 3.1.5, Action a. addresses both one pump and corresponding explosive valve inoperable. TSTF-505 changes are incorporated.
Reactor Protection System (RPS) Instrumentation	**3.3.1.1**	**3.3.1**		
Number of operable channels in either trip system for one or more Functional Units less than the minimum required operable channels per trip system.	-----------	3.3.1.a	Yes	This is a plant-specific condition with an action to place either the affected trip system or at least one inoperable channel in the affected trip system in the tripped condition and an allowed outage time of 1 hour. LGS proposes to apply a RICT to the existing LGS TS 3.3.1, Action a. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
One or more required channels inoperable.	3.3.1.1.A.1 3.3.1.1.A.2	3.3.1.b	Yes	TSTF-505 changes are incorporated.

Cross-Reference of TSTF-505 and Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
One or more Functions with one or more required channels inoperable in both trip systems.	3.3.1.1.B.1 3.3.1.1.B.2	3.3.1.c	Yes	TSTF-505 changes are incorporated. However, under certain circumstances, for one or more Functions with one or more required channels inoperable, a loss of function may occur. Therefore, a footnote is added which prohibits applying a RICT when RPS trip capability is not maintained.
Source Range Monitor (SRM) Instrumentation	**3.3.1.2**	**3.3.7.6**		
One or more required SRMs inoperable in MODE 2.	3.3.1.2.A	3.3.7.6.a	No	TSTF-505 changes are excluded. This TS function is not modeled in the LGS PRA.
Feedwater and Main Turbine High Water Level Trip Instrumentation	**3.3.2.2**	**3.3.9**		
One feedwater and main turbine high water level trip channel inoperable.	3.3.2.2.A	3.3.9.b	Yes	TSTF-505 changes are incorporated.
Two or more feedwater and main turbine high water level trip channels inoperable.	3.3.2.2.B	3.3.9.c	Yes	TSTF-505 changes are incorporated. However, under certain circumstances, with two or more feedwater and main turbine high water level trip channels inoperable, a loss of function may occur. Therefore, a footnote is added which prohibits applying a RICT when trip capability is not maintained.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation	**3.3.4.1**	**3.3.4.2**		
One or more required channels inoperable.	3.3.4.1.A	3.3.4.2.b 3.3.4.2.c.1	Yes Yes	TSTF-505 changes are incorporated. However, under certain circumstances, with more than one required channel inoperable, a loss of function may occur. Therefore, a footnote is added which prohibits applying a RICT when trip capability is not maintained.
One trip system inoperable	----------	3.3.4.2.d	Yes	This is a plant-specific condition with a restoration action and allowed outage time of 72 hours. Trip capability is maintained through the other trip system. Therefore, LGS proposes to apply a RICT to the existing LGS TS 3.3.4.2, Action d. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation	**3.3.4.2**	**3.3.4.1**		
One or more channels inoperable.	3.3.4.2.A	3.3.4.1.b 3.3.4.1.c.1	Yes Yes	TSTF-505 changes are incorporated. However, under certain circumstances, with more than one channel inoperable, a loss of function may occur. Therefore, a footnote is added which prohibits applying a RICT when trip capability is not maintained.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
One trip system inoperable.	-----------	3.3.4.1.d	Yes	This is a plant-specific condition with a restoration action and allowed outage time of 72 hours. Trip capability is maintained through the other trip system. Therefore, LGS proposes to apply a RICT to the existing LGS TS 3.3.4.1, Action d. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
Emergency Core Cooling System (ECCS) Instrumentation	**3.3.5.1**	**3.3.3**		
As required by Required Action A.1 and referenced in Table 3.3.5.1-1 (Functions 1.a, 1.b, 2.a, and 2.b; 3.a and 3.b).	3.3.5.1.B.3	3.3.3.b	Yes Yes	LGS TS Table 3.3.3-1, Action 30 is associated with the functions that correspond to the TSTF-505 Functions 1.a, 1.b, 2.a, and 2.b associated with Action B. TSTF-505 changes are incorporated. LGS Table 3.3.3-1, Action 34.a is associated with the functions that correspond to the TSTF-505 Functions 3.a and 3.b associated with Action B. TSTF-505 changes are incorporated.
As required by Required Action A.1 and referenced in Table 3.3.5.1-1 (Functions 1.c, 2.c, 2.d, and 2.f; 1.e, 2.h, and 3.g).	3.3.5.1.C.2	3.3.3.b	No Yes	LGS TS Table 3.3.3-1, Action 31 is associated with the functions that correspond to the TSTF-505 Functions 1.c, 2.c, 2.d, and 2.f associated with Action C; however, the LGS Action is to declare the associated ECCS inoperable. Therefore, the TSTF-505 changes are NOT applicable to these LGS functions. LGS TS Table 3.3.3-1, Action 33 is associated with the functions that correspond to the TSTF-505 Functions 1.e, 2.h, and 3.g associated with Action C. TSTF-505 changes are incorporated.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
As required by Required Action A.1 and referenced in Table 3.3.5.1-1 (Functions 3.d and 3.e).	3.3.5.1.D.2.1	3.3.3.b	Yes	LGS TS Table 3.3.3-1, Action 35 is associated with the functions that correspond to the TSTF-505 Functions 3.d and 3.e associated with Action D. TSTF-505 changes are incorporated.
As required by Required Action A.1 and referenced in Table 3.3.5.1-1 (Functions 1.d, 2.g, and 3.f).	3.3.5.1.E.2	3.3.3.b	No	LGS TS Table 3.3.3-1 does not include any functions that correspond to the TSTF-505 Functions associated with Action E. Therefore, TSTF-505 changes are not applicable to the LGS TS.
As required by Required Action A.1 and referenced in Table 3.3.5.1-1 (Functions 4.a, 4.b, 4.d, 5.a, 5.b, and 5.d).	3.3.5.1.F.2	3.3.3.b	Yes No	LGS TS Table 3.3.3-1, Action 30 is associated with the functions that correspond to the TSTF-505 Functions 4.a, 4.b, 5.a, and 5.b associated with Action F. TSTF-505 changes are incorporated. LGS TS Table 3.3.3-1, Action 31 is associated with the functions that correspond to the TSTF-505 Functions 4.d and 5.d associated with Action F; however, the LGS Action is to declare the associated ECCS inoperable. Therefore, the TSTF-505 changes are NOT applicable to these LGS functions.
Either ADS trip system inoperable.	-----------	3.3.3.c.1 3.3.3.c.2	Yes Yes	LGS TS 3.3.3, Actions c.1 and c.2 are plant-specific conditions with restoration actions and allowed outage times of 7 days and 72 hours, respectively. Trip capability is maintained through the other trip system. Therefore, LGS proposes to apply a RICT to the existing LGS TS 3.3.3, Actions c.1 and c.2. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.

Cross-Reference of TSTF-505 and Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
As required by Required Action A.1 and referenced in Table 3.3.5.1-1 (Functions 4.c, 4.e, 4.f, 4.g, 5.c, 5.e, 5.f, and 5.g; 4.h and 5.h).	3.3.5.1.G.2	3.3.3.b	No Yes	LGS TS Table 3.3.3-1, Action 31 is associated with the functions that correspond to the TSTF-505 Functions 4.c, 4.e, 4.f, 4.g, 5.c, 5.e, 5.f, and 5.g associated with Action G; however, the LGS Action is to declare the associated ECCS inoperable. Therefore, the TSTF-505 changes are NOT applicable to these LGS functions. LGS TS Table 3.3.3-1, Action 33 is associated with the functions that correspond to the TSTF-505 Functions 4.h and 5.h associated with Action G. TSTF-505 changes are incorporated.
Reactor Core Isolation Cooling (RCIC) System Instrumentation	**3.3.5.2**	**3.3.5**		
As required by Required Action A.1 and referenced in Table 3.3.5.2-1 (Function 1).	3.3.5.2.B.2	3.3.5.b	Yes	LGS TS Table 3.3.5-1, Action 50.a is associated with the function that corresponds to the TSTF-505 Function 1 associated with Action B. TSTF-505 changes are incorporated.
As required by Required Action A.1 and referenced in Table 3.3.5.2-1 (Functions 3 and 4).	3.3.5.2.D.2.1	3.3.5.b	Yes No	LGS TS Table 3.3.5-1, Action 52 is associated with the function that corresponds to the TSTF-505 Function 3 associated with Action D. TSTF-505 changes are incorporated. LGS TS Table 3.3.5-1 does not include any function that corresponds to the TSTF-505 Function 4 associated with Action D. Therefore, TSTF-505 changes are not applicable to the LGS TS for this Function.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
Primary Containment Isolation Instrumentation	**3.3.6.1**	**3.3.2**		
One or more required channels inoperable (Functions 2.a, 2.b, 6.b, 7.a, and 7.b; Functions other than Functions 2.a, 2.b, 6.b, 7.a, and 7.b).	3.3.6.1.A	3.3.2.b.1 3.3.2.b.2.a 3.3.2.b.2.b	Yes Yes Yes	LGS TS 3.3.2, Action b.1 is for inoperable channels where the tripped condition would cause an isolation. For inoperable channels where the tripped condition would not cause an isolation, LGS TS 3.3.2, Action b.2.a is for trip functions common to RPS instrumentation and TS 3.3.2, Action b.2.b is for trip functions not common to RPS instrumentation. TSTF-505 changes are incorporated.
Low-Low-Set (LLS) Instrumentation	**3.3.6.3**	**---------**		The LGS TS do not contain this TS. Therefore, a change is not proposed to the LGS TS.
Loss of Power (LOP) Instrumentation	**3.3.8.1**	**3.3.3**		
One or more channels inoperable.	3.3.8.1.A	3.3.3.b	No	Corresponding LGS TS Table 3.3.3-1, Action 36 requires declaring the associated emergency diesel generator and offsite source breaker inoperable. In addition, corresponding LGS TS Table 3.3.3-1, Action 37 requires placing the inoperable device in bypass. Both of these actions are outside the scope of TSTF-505. Therefore, a change is not proposed to the LGS TS.

Cross-Reference of TSTF-505 and Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
Safety/Relief Valves (SRVs)	**3.4.3**	**3.4.2**		
One [or two] required SRV(s) inoperable.	3.4.3.A	3.4.2.a	No	NUREG-1433, TS 3.4.3.A allows 14 days to restore the required SRV(s) to an operable status for one or two SRVs inoperable, and TS 3.4.3.B requires a plant shutdown for three or more SRVs inoperable. LGS TS 3.4.2, Action a. does not have a 14-day allowance for one or two SRVs inoperable but rather requires a plant shutdown for one or more SRV(s) inoperable (similar to NUREG-1433, TS 3.4.3, Required Action B). This Condition involves a loss of function; therefore, a change is not proposed to the LGS TS.
ECCS - Operating	**3.5.1**	**3.5.1**		
One low pressure ECCS injection/spray subsystem inoperable or one LPCI pump in both LPCI subsystems inoperable.	3.5.1.A	3.5.1.a.1 3.5.1.b.4	Yes Yes	The corresponding LGS TS 3.5.1, Action a.1 is for one core spray system (CSS) subsystem inoperable with at least two low pressure coolant injection (LPCI) subsystems operable, and TS 3.5.1, Action b.4 is for two LPCI subsystems inoperable with at least one CS subsystem operable. TSTF-505 changes are incorporated. Note: LGS TS 3.5.1, Action b.1 corresponds to TSTF-505, Condition A for one LPCI subsystem inoperable; however, this LGS Action already has a 30-day allowed outage time. Therefore, TSTF-505 changes are not applicable to LGS TS 3.5.1, Action b.1.
HPCI System inoperable.	3.5.1.C	3.5.1.c.1	Yes	TSTF-505 changes are incorporated.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
HPCI System inoperable and Condition A entered.	3.5.1.D	3.5.1.c.2	Yes	TSTF-505 changes are incorporated.
One ADS valve inoperable.	3.5.1.E	3.5.1.d.1	Yes	TSTF-505 changes are incorporated.
One ADS valve inoperable and Condition A entered.	3.5.1.F	---------		The LGS TS do not contain this TS. Therefore, a change is not proposed to the LGS TS.
Three LPCI subsystems inoperable with both Core Spray subsystems operable.	----------	3.5.1.b.5	Yes	This is a plant-specific condition with a restoration action and allowed outage time of 72 hours. LGS proposes to apply a RICT to the existing LGS TS 3.5.1, Action B.5. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
RCIC [Reactor Core Isolation Cooling] System	**3.5.3**	**3.7.3**		
RCIC system inoperable.	3.5.3.A	3.7.3.a	Yes	TSTF-505 changes are incorporated.

Cross-Reference of TSTF-505 and Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
Primary Containment Air Lock	**3.6.1.2**	**3.6.1.3**		
One primary containment air lock door inoperable.	----------	3.6.1.3.a.1	Yes	LGS TS 3.6.1.3, Action a.1 is for one primary containment air lock door inoperable. This corresponds to NUREG-1433, TS 3.6.1.2, Condition A, which TSTF-505 has excluded because the Condition contains mitigating actions and requires periodic performance of an action but does not include any restoration action. Similarly, LGS TS 3.6.1.3, Action a.1 contains mitigating actions; however, this LGS Action also includes a restoration action with an allowed outage time of 24 hours, which meets the criteria established by TSTF-505. Therefore, LGS proposes to apply a RICT to the restore action in existing LGS TS 3.6.1.3, Action a.1.
Primary containment air lock inoperable for reasons other than Condition A or B.	3.6.1.2.C	3.6.1.3.b	Yes	TSTF-505 changes are incorporated.
Primary Containment Isolation Valves (PCIVs)	**3.6.1.3**	**3.6.3** **3.4.7**		**LGS PCIVs** **LGS Main Steam Isolation Valves (MSIVs)**
For penetration flow paths with two or more PCIVs, one or more penetration flow paths with one PCIV inoperable.	3.6.1.3.A	3.6.3.a 3.4.7.a	Yes Yes	NUREG-1433, TS 3.6.1.3 applies to PCIVs, including MSIVs. LGS TS 3.6.3, Action a. applies to PCIVs other than the MSIVs. LGS TS 3.4.7, Action a. applies to MSIVs. TSTF-505 changes are incorporated into both LGS TS 3.6.3, Action a. and LGS TS 3.4.7, Action a.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
One or more penetration flow paths with one or more containment purge valves not within purge valve leakage limits.	3.6.1.3.E	3.6.1.2	No	Containment purge valves are captured as part of the LGS TS 3.6.1.2. However, the allowed outage time is based on a situation, i.e., prior to increasing reactor coolant system temperature above 200ºF, which does not meet the criteria of TSTF-505 for applying a RICT. Therefore, a change is not proposed to the LGS TS.
Reactor Building-to-Suppression Chamber Vacuum Breakers	**3.6.1.7**	**---------**		The LGS TS do not contain this TS. Therefore, a change is not proposed to the LGS TS.
Suppression Chamber-to-Drywell Vacuum Breakers	**3.6.1.8**	**3.6.4.1**		
One required suppression chamber-to-drywell vacuum breaker inoperable for opening.	3.6.1.8.A	3.6.4.1.a	Yes	TSTF-505 changes are incorporated.
Residual Heat Removal (RHR) Suppression Pool Cooling	**3.6.2.3**	**3.6.2.3**		
One RHR suppression pool cooling subsystem inoperable.	3.6.2.3.A	3.6.2.3.a	Yes	TSTF-505 changes are incorporated.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
One RHR suppression pool cooling subsystem inoperable during RHRSW subsystem piping repairs.	----------	3.6.2.3.a Footnote **	Yes	This is a plant-specific condition which allows the 72-hour allowed outage time of TS 3.6.2.3, Action a. to be extended up to 7 days during repairs of the RHRSW subsystem piping. This allowed outage time extension is linked to the restoration action of TS 3.6.2.3, Action a. LGS proposes to apply a RICT to the existing LGS TS 3.6.2.3, Action a. footnote. This is consistent with the TSTF-505 changes to TS 3.6.2.3.A. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
Residual Heat Removal (RHR) Suppression Pool Spray	**3.6.2.4**	**3.6.2.2**		
One RHR suppression pool spray subsystem inoperable.	3.6.2.4.A	3.6.2.2.a	Yes	TSTF-505 changes are incorporated.
Drywell Cooling System Fans	**3.6.3.1**	**3.6.6.2**		
Two [required] [drywell cooling system fans] inoperable.	3.6.3.1.B.2	----------	No	The LGS TS do not contain this TS. Therefore, a change is not proposed to the LGS TS.
Standby Gas Treatment (SGT) System	**3.6.4.3**	**3.6.5.3**		
One standby gas treatment subsystem inoperable.	----------	3.6.5.3.a.1 (Unit 1) 3.6.5.3.a.2 (Unit 2)	Yes	The TSTF-505 markup for this TS indicates that a quantitative RICT cannot be performed for this TS. The SGT system is modeled in the Limerick PRA. Therefore, a quantitative RICT can be performed for this LGS TS. LGS proposes to apply a RICT to the existing LGS TS 3.6.5.3, Action a.1 (Unit 1)/Action a.2 (Unit 2).

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
One SGTS subsystem inoperable and the other SGTS subsystem with an inoperable Unit 1 diesel generator.	----------	3.6.5.3.a.3 (Unit 2)	Yes	This is a plant-specific condition with a restoration action and allowed outage time of 72 hours. LGS proposes to apply a RICT to the existing LGS TS 3.6.5.3, Action a.3. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
Unit 1 diesel generators for both SGTS subsystems inoperable.	----------	3.6.5.3.a.4 (Unit 2)	Yes	This is a plant-specific condition with a restoration action and allowed outage time of 72 hours. LGS proposes to apply a RICT to the existing LGS TS 3.6.5.3, Action a.4. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
Residual Heat Removal Service Water (RHRSW) System	**3.7.1**	**3.7.1.1**		
One RHRSW pump in each subsystem inoperable.	3.7.1.B	3.7.1.1.a.2	Yes	TSTF-505 changes are incorporated.
One RHRSW subsystem inoperable for reasons other than Condition A.	3.7.1.C	3.7.1.1.a.3	Yes	TSTF-505 changes are incorporated.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
'A' RHRSW subsystem is inoperable to allow for repairs of the 'A' RHRSW subsystem piping.	----------	3.7.1.1.a.3.a)	Yes	This is a plant-specific condition which allows the 72-hour allowed outage time of TS 3.7.1.1, Action a.3 to be extended up to 7 days during repairs of the 'A' RHRSW subsystem piping. This allowed outage time extension is linked to the restoration action of TS 3.7.1.1, Action a.3. LGS proposes to apply a RICT to the existing LGS TS 3.7.1.1, Action a.3.a). Compensatory measures will be established under this condition as required by TS 3.7.1.1, Action a.3.a).1 and a.3.a).2. This is consistent with the TSTF-505 changes to TS 3.7.1.C. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
'B' RHRSW subsystem is inoperable to allow for repairs of the 'B' RHRSW subsystem piping.	----------	3.7.1.1.a.3.b)	Yes	This is a plant-specific condition which allows the 72-hour allowed outage time of TS 3.7.1.1, Action a.3 to be extended up to 7 days during repairs of the 'B' RHRSW subsystem piping. This allowed outage time extension is linked to the restoration action of TS 3.7.1.1, Action a.3. LGS proposes to apply a RICT to the existing LGS TS 3.7.1.1, Action a.3.b). Compensatory measures will be established under this condition as required by TS 3.7.1.1, Action a.3.b).1 and a.3.b).2. This is consistent with the TSTF-505 changes to TS 3.7.1.C. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
Three RHRSW pump/diesel generator pairs inoperable.	---------	3.7.1.1.a.6	Yes	This is a plant-specific condition with a restoration action and allowed outage time of 7 days. LGS proposes to apply a RICT to the existing LGS TS 3.7.1.1, Action a.6. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
Plant Service Water (PSW)] System and [Ultimate Heat Sink (UHS)	**3.7.2**	**3.7.1.2**		**LGS, TS 3.7.1.2 is the Emergency Service Water (ESW) System**
One PSW pump in each subsystem inoperable.	3.7.2.B	3.7.1.2.a.2	No	The NUREG-1433, TS 3.7.2, Condition B has a CT of 7 days. The corresponding LGS TS 3.7.1.2, Action a.2 has an allowed outage time of 30 days. This already meets the limit of 30 days in accordance with TSTF-505. Therefore, a change is not proposed to the LGS TS.
One or more cooling towers with one cooling tower fan inoperable.	3.7.2.C	---------		The LGS TS do not contain this TS. Therefore, a change is not proposed to the LGS TS.
One PSW subsystem inoperable for reasons other than Condition[s] A [and C].	3.7.2.E	3.7.1.2.a.3	Yes	TSTF-505 changes are incorporated.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
One ESW loop inoperable during RHRSW subsystem piping repairs.	---------	3.7.1.2.a.3 Footnote #	Yes	This is a plant-specific condition which allows the 72-hour allowed outage time of TS 3.7.1.2, Action a.3 to be extended up to 7 days during repairs of the RHRSW subsystem piping. This allowed outage time extension is linked to the restoration action of TS 3.7.1.2, Action a.3. LGS proposes to apply a RICT to the existing LGS TS 3.7.1.2, Action a.3 footnote. This is consistent with the TSTF-505 changes to TS 3.7.2.E. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
Three ESW pump/diesel generator pairs inoperable.	---------	3.7.1.2.a.4	Yes	This is a plant-specific condition with a restoration action and allowed outage time of 72 hours. LGS proposes to apply a RICT to the existing LGS TS 3.7.1.2, Action a.4. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
Main Turbine Bypass System	**3.7.7**	**3.7.8**		
Requirements of the LCO not met or Main Turbine Bypass System inoperable.	3.7.7.A	3.7.8	Yes	TSTF-505 changes are incorporated.
AC Sources – Operating	**3.8.1**	**3.8.1.1**		
One [required] offsite circuit inoperable.	3.8.1.A.3	3.8.1.1.f	Yes	TSTF-505 changes are incorporated.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
One [required] DG inoperable.	3.8.1.B.4	3.8.1.1.a	No	The NUREG-1433, TS 3.8.1, Condition B has a CT of 72 hours. The corresponding LGS TS 3.8.1.1, Action a. has an allowed outage time of 30 days. This already meets the limit of 30 days in accordance with TSTF-505. Therefore, a change is not proposed to the LGS TS.
Two [required] offsite circuits inoperable.	3.8.1.C.2	3.8.1.1.g	Yes	LGS TS 3.8.1.1, Action g contains an action to restore at least one of the inoperable offsite circuits to an operable status within 24 hours, and an additional action to restore at least two offsite circuits to an operable status within 72 hours from time of initial loss. LGS proposes to modify TS 3.8.1.1, Action g. to include the option to use the RICT Program, consistent with TSTF-505.
One [required] offsite circuit inoperable. AND One [required] DG inoperable.	3.8.1.D.1 3.8.1.D.2	3.8.1.1.d	Yes	The Required Action for NUREG-1433, TS 3.8.1, Condition D is to restore either the offsite circuit or the diesel generator to an operable status. The corresponding LGS TS 3.8.1.1, Action d. requires restoring at least two offsite circuits to operable status. TSTF-505 changes are incorporated.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
Two [or three] [required] DGs inoperable.	3.8.1.E	3.8.1.1.b 3.8.1.1.c	Yes No	NUREG-1433, TS 3.8.1, Condition E involves either two or three diesel generators inoperable which is excluded per TSTF-505, Revision 2. The corresponding LGS TS 3.8.1.1, Action b. involves two diesel generators inoperable, and Action c. involves three diesel generators inoperable. TSTF-505 changes are incorporated into LGS TS 3.8.1.1, Action b. only since this does not represent a loss of function for LGS, which has four diesel generators per unit. However, Action c does involve a loss of function; therefore, a change is not proposed to LGS TS 3.8.1.1, Action c.
Two DGs inoperable during RHRSW subsystem piping repairs.	----------	3.8.1.1.b Footnote *	Yes	This is a plant-specific condition which allows the 72-hour allowed outage time of TS 3.8.1.1, Action b. to be extended up to 7 days during repairs of the RHRSW subsystem piping. This allowed outage time extension is linked to the restoration action of TS 3.8.1.1, Action b. LGS proposes to apply a RICT to the existing LGS TS 3.8.1.1, Action b. footnote. This is consistent with the TSTF-505 changes to TS 3.8.1.E. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
One [required] automatic load sequencer inoperable.	3.8.1.F	---------		The LGS TS do not contain this TS. Therefore, a change is not proposed to the LGS TS.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	**TSTF-505 Tech Spec**	**LGS Tech Spec**	**Apply RICT?**	**Comments**
One offsite circuit and two diesel generators inoperable.	----------	3.8.1.1.h	Yes	This is a plant-specific condition with an action to restore at least one of the inoperable AC sources to an operable status within 12 hours, and an additional action to restore at least two offsite circuits and at least three diesel generators to an operable status within 72 hours. Therefore, LGS proposes to modify TS 3.8.1.1, Action h. to include the option to use the RICT Program, consistent with TSTF-505. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
For two trains systems, with one or more diesel generators inoperable.	----------	3.8.1.1.e.1	Yes	This is a plant-specific condition with a restoration action and allowed outage time of 72 hours. LGS proposes to apply a RICT to the existing LGS TS 3.8.1.1, Action e.1. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
For two trains systems, with one or more diesel generators inoperable during RHRSW subsystem piping repairs	----------	3.8.1.1.e.1 Footnote *	Yes	This is a plant-specific condition which allows the 72-hour allowed outage time of TS 3.8.1.1, Action e.1 to be extended up to 7 days during repairs of the RHRSW subsystem piping. This allowed outage time extension is linked to the restoration action of TS 3.8.1.1, Action e.1. LGS proposes to apply a RICT to the existing LGS TS 3.8.1.1, Action e.1. footnote. This is consistent with the similar changes to the TS allowed outage times for RHRSW piping repairs. This is acceptable because the TSTF states that there may also be plant-specific TS to which changes of the type presented in the TSTF may be applied.
DC Sources - Operating	**3.8.4**	**3.8.2.1**		
One or two battery chargers on one division inoperable.	3.8.4.A.3	3.8.2.1.a.3	Yes	TSTF-505 changes are incorporated.
One or two batteries on one division inoperable.	3.8.4.B	3.8.2.1.c	Yes	TSTF-505 changes are incorporated.
One DC electrical power subsystems inoperable.	3.8.4.C	---------		The LGS TS do not contain this TS. Therefore, a change is not proposed to the LGS TS.
Inverters - Operating	**3.8.7**	**---------**		**The LGS TS do not contain this TS. Therefore, a change is not proposed to the LGS TS.**

Cross-Reference of TSTF-505 and
Limerick Generating Station (LGS) Technical Specifications

Tech Spec Description	TSTF-505 Tech Spec	LGS Tech Spec	Apply RICT?	Comments
Distribution Systems - Operating	**3.8.9**	**3.8.3.1**		
One or more AC electrical power distribution subsystems inoperable.	3.8.9.A	3.8.3.1.a	Yes	TSTF-505 changes are incorporated. EDITORIAL: The condition specified in LGS TS 3.8.3.1, Action a. is one AC distribution system division not energized, rather than inoperable. The action is to reenergize the division.
One or more AC vital buses inoperable.	3.8.9.B	---------		The LGS TS do not contain this TS. Therefore, a change is not proposed to the LGS TS.
One or more DC electrical power distribution subsystems inoperable.	3.8.9.C	3.8.3.1.b	Yes	TSTF-505 changes are incorporated. EDITORIAL: The condition specified in LGS TS 3.8.3.1, Action b. is one DC distribution system division not energized, rather than inoperable. The action is to reenergize the division.
Programs and Manuals	**5.5**	**6.8.4**		
Programs and Manuals	5.5.18	[NEW TS] 6.8.4.m		The LGS TS do not currently contain this program. The new RICT Program will be added to the LGS TS 6.8.4 consistent with TSTF-505.

ATTACHMENT 5

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Information Supporting Instrumentation Redundancy and Diversity

Information Supporting Instrumentation Redundancy and Diversity

The following Instrumentation Technical Specifications (TS) Sections are included in this TSTF-505 License Amendment Request (LAR) for Limerick Generating Station (LGS), Units 1 and 2.

1. Reactor Protection System – TS Section 3.3.1
2. Isolation Actuation – TS Section 3.3.2
3. Emergency Core Cooling System Actuation – TS Section 3.3.3
4. Anticipated Transient Without Scram Recirculation Pump Trip – TS Section 3.3.4.1
5. End-of-Cycle Recirculation Pump Trip – TS Section 3.3.4.2
6. Reactor Core Isolation Cooling System Actuation – TS Section 3.3.5
7. Feedwater/Main Turbine Trip System Actuation – TS Section 3.3.9

LGS TS Section 3.3 Limiting Conditions for Operation (LCOs) were developed to assure that LGS maintains necessary redundancy and diversity, and complies with the "single failure" design criterion as defined in IEEE-279-1971 and diversity requirements as defined in Appendix A, "General Design Criteria for Nuclear Power Plants" (GDC), to Part 50 of 10 CFR, GDC-22, "Protection System Independence."

Included below is a description of the redundant and diverse means available to mitigate accidents for which each identified instrumentation and control function defined in TS 3.3 above is designed to prevent.

1. Reactor Protection System (RPS)

Reference: TS 3.3.1 Reactor Protection System

The RPS design creates defense-in-depth due to the redundancy of the channels for each Functional Unit.

- Each Functional Unit has multiple channels.
- Each Functional Unit will cause a reactor trip with 2/4 tripped channels.
- A failed channel does not cause or prevent a trip.

Diverse inputs trip the reactor (UFSAR Table 7.2-2):

2/4 is defined as four channels, two trip systems, two channels per trip system arranged in a one-out-of-two twice (de-energize to trip) logic, e.g., (Channel A1 or Channel A2) and (Channel B1 or Channel B2).

- Simulated Thermal Power (Upscale) – 2/4
  4 voters/channels (two of three APRM votes needed to trip each voter)
- Neutron Flux (Upscale) – 2/4
  4 voters/channels (two of three APRM votes needed to trip each voter)
- OPRM oscillation amplitude and count (Upscale) – 2/4
  4 voters/channels (two of three APRM votes needed to trip each voter)
- Intermediate Range Monitors Neutron Flux (High) – 2/4
  2 monitors per channel (TS requires only 3 for A1/A2 and 3 for B1/B2)
- Primary Containment Pressure (High) – 2/4
- Reactor Vessel Pressure (High) – 2/4
- Reactor Vessel Level (Low – Level 3) – 2/4

Information Supporting Instrumentation Redundancy and Diversity

- Main Steam Line Isolation Valve Position (Closure) – 2/4
  Channel A1 is either valve in steam line A and steam line B
  Channel A2 is either valve in steam line C and steam line D
  Channel B1 is either valve in steam line A and steam line C
  Channel B2 is either valve in steam line B and steam line D
  Three steam lines needed for a full SCRAM
- Turbine Control Valve Fast Closure (Trip Oil Pressure - Low) – 2/4
- Turbine Main Stop Valve Position (Closure) – 2/4
  Channel A1 is valve 3 and valve 4
  Channel A2 is valve 1 and valve 2
  Channel B1 is valve 1 and valve 3
  Channel B2 is valve 2 and valve 4
  Three valves needed for a full SCRAM
- CRD SCRAM discharge volume level transmitter (High) – 2/4
- CRD SCRAM discharge volume level float (High) – 2/4
- Reactor Mode Switch Position – 2/4
  Single Mode Switch with 4 channels.
- Manual – 2/4

In addition, the Redundant Reactivity Control System (RRCS) is designed to provide a redundant and diverse method of shutting down the reactor in the unlikely event that the RPS does not scram the reactor. A signal is transmitted to open the Alternate Rod Insertion (ARI) valves that vent the Control Rod Drive (CRD) scram air header to insert the control rods into the reactor. A signal is transmitted to the recirculation pump trip (RPT) breakers to trip the reactor recirculation pumps to reduce the reactor power (negative void reactivity feedback). A signal is transmitted to initiate the Standby Liquid Control system to inject boron into the Reactor Vessel and a closure signal to the RWCU Isolation Valves to prevent removal of the injected boron.

The RRCS logic is provided in Section 4 ANTICIPATED TRANSIENT WITHOUT SCRAM RECIRCULATION PUMP TRIP (ATWS-RPT).

2. ISOLATION ACTUATION

Reference: TS 3.3.2 Isolation Actuation

The Isolation Actuation design creates defense-in-depth due to the redundancy of the channels for each Trip Function.

- Each Trip Function has multiple channels.
- Each Trip Function will cause an Isolation Actuation with 2/2, 2/4, or 1/1 tripped channels.
- A failed channel does not prevent a trip but may cause a trip depending on the logic design.

Diverse inputs for Isolation Actuation (UFSAR Table 6.2-17):

2/2 is defined as four channels, two trip systems, two channels per trip system arranged in a two-out-of-two once (de-energize to trip) logic, e.g., (Channel A and Channel B) or (Channel C and Channel D). HPCI and RCIC are energize to trip.

Information Supporting Instrumentation Redundancy and Diversity

2/4 is defined as four channels, two trip systems, two channels per trip system arranged in a one-out-of-two twice (de-energize to trip) logic, e.g., (Channel A or Channel C) and (Channel B or Channel D).

1/1 is defined as two channels, two trip systems, one channel per trip system arranged in a one-out-of-one once (de-energize to trip) logic, e.g., (Channel A) or (Channel D). HPCI and RCIC are energize to trip.

- Main Steam Line Isolation
    - Reactor Vessel Water Level (Low, Low – Level 2) – 2/2
    - Reactor Vessel Water Level (Low, Low, Low – Level 1) – 2/4
      Except Main Steam Line drains - 2/2
    - Main Steam Line Pressure (Low) – 2/4
    - “A” Main Steam Line Flow (High) – 2/4
    - “B” Main Steam Line Flow (High) – 2/4
    - “C” Main Steam Line Flow (High) – 2/4
    - “D” Main Steam Line Flow (High) – 2/4
    - Condenser Vacuum (Low) – 2/4
      Except Main Steam Line drains - 2/2
    - Outboard MSIV Room Temperature (High) – 2/4
      Except Main Steam Line Drains - 2/2
    - Turbine Enclosure – Main Steam Line Tunnel Temperature (High) – 2/4
      7 sensor locations – any single sensor trips channel
      Except Main Steam Line Drains - 2/2
    - Manual – 2/4
      Except Main Steam Line Drains – 1/1

- RHR System Shutdown Cooling Mode Isolation
    - Reactor Vessel Water Level (Low – Level 3) - 2/2
    - Reactor Vessel Pressure (High) - 1/1
    - Manual – 1/1

- Reactor Water Cleanup System Isolation
    - RWCS Delta Flow (High) – 1/1
    - RWCS Area Temperature (High) – 1/1
      6 sensor locations – any single sensor trips channel
    - RWCS Area Ventilation Delta Temperature (High) – 1/1
      6 sensor locations – any single sensor trips channel
    - Standby Liquid Control Initiation – 1/3 - each of the 3 pumps isolates either the Inboard or Outboard.
    - Reactor Vessel Water Level (Low, Low – Level 2) - 2/2
    - Manual – 1/1

- High Pressure Coolant Injection System Isolation
    - HPCI Steam Line Delta Pressure (High) and Timer – 1/1
    - HPCI Steam Supply Pressure (Low) – 2/2

Information Supporting Instrumentation Redundancy and Diversity

  - HPCI Turbine Exhaust Diaphragm Pressure (High) – 2/2
  - HPCI Equipment Room Temperature (High) - 1/1
  - HPCI Equipment Room Delta Temperature (High) – 1/1
  - HPCI Piping Routing Area Temperature (High) -1/1
    4 sensor locations – any single sensor trips channel.
  - Manual – 1/1

- Reactor Core Isolation Cooling System Isolation
  - RCIC Steam Line Delta Pressure (High) and Timer – 1/1
  - RCIC Steam Supply Pressure (Low) – 2/2
  - RCIC Turbine Exhaust Diaphragm Pressure (High) – 2/2
  - RCIC Equipment Room Temperature (High) - 1/1
  - RCIC Equipment Room Delta Temperature (High) – 1/1
  - RCIC Piping Routing Area Temperature (High) -1/1
    5 sensor locations – any single sensor trips channel.
  - Manual – 1/1

- Primary Containment Isolation
  - Reactor Vessel Water Level (Low, Low – Level 2) - 2/2
  - Reactor Vessel Water Level (Low, Low, Low – Level 1) - 2/2
  - Drywell Pressure (High) - 2/2
  - North Stack Effluent Radiation (High) – 1/1
  - Reactor Enclosure Ventilation Exhaust Duct Radiation (High) - 2/2
  - Drywell Pressure (High)/Reactor Pressure (Low) - 2/2
  - Primary Containment Instrument Gas to Drywell Delta Pressure (Low) - 1/1
  - Manual – 1/1

- Secondary Containment Isolation
  - Reactor Vessel Water Level (Low, Low – Level 2) - 2/2
  - Drywell Pressure (High) - 2/2
  - Refueling Area Unit 1 Ventilation Exhaust Duct Radiation (High) – 2/2
  - Refueling Area Unit 2 Ventilation Exhaust Duct Radiation (High) – 2/2
  - Reactor Enclosure Ventilation Exhaust Duct Radiation (High) - 2/2
  - Reactor Enclosure Manual – 1/1
  - Refueling Area Manual – 1/1

3. EMERGENCY CORE COOLING SYSTEM (ECCS)

Reference: TS 3.3.3 Emergency Core Cooling System Actuation

The ECCS design creates defense-in-depth due to the redundancy of the channels for the Trip Function (ECCS System Actuation).

- Trip Function (ECCS System Actuation) has multiple channels.
- Trip Function (ECCS System Actuation) will cause a Trip Function with 2/2, 4/4, 2/4 or 1/2 tripped channels.
- A failed channel does not cause or prevent a trip (except Manual).

Information Supporting Instrumentation Redundancy and Diversity

2/2 is defined as two channels, one trip system arranged in a two-out-of-two once (energize to initiate) logic, e.g., (Channel A and Channel B).

4/4 is defined as four channels, one trip system arranged in a four-out-of-four (energize to initiate) logic, e.g., (Channel A and B and C and D)

2/4 is defined as four channels, one trip system arranged in a one-out-of-two twice (energize to initiate) logic, e.g., (Channel A or Channel C) and (Channel B or Channel D).

1/2 is defined as two channels, one trip system arranged in a one-out-of-two once (energize to initiate) logic, e.g., (Channel A or Channel B).

- Core Spray System (2 divisions which consist of 2 pumps per division)
  - Reactor Vessel Water Level – (Low, Low, Low – Level 1) – 2/2 for each pump
    1 of the 2 channels can be Drywell Pressure/Reactor Vessel Pressure
  - Drywell Pressure (High) – 4/4 for each pump (combined with Reactor Vessel Pressure)
    2 are Drywell Pressure and 2 are Reactor Vessel Pressure
    2 of the four channels can be satisfied by one Reactor Vessel Water Level
  - Reactor Vessel Pressure – (Low – Permissive) – 4/4 for each pump (combined with Drywell Pressure)
    2 are Drywell Pressure and 2 are Reactor Vessel Pressure
    2 of the four channels can be satisfied by one Reactor Vessel Water Level
  - Reactor Vessel Pressure for Injection Valve– (Low – Permissive) – 2/4
    2 pumps share a common injection
  - Manual – 1/pump - one trip system per pump

- Low Pressure Coolant Injection Mode of RHR System (4 divisions)
  - Reactor Vessel Water Level – (Low, Low, Low – Level 1) – 2/2
    1 of the 2 channels can be Drywell Pressure/Reactor Vessel Pressure
  - Drywell Pressure (High) – 4/4
    2 are Drywell Pressure and 2 are Reactor Vessel Pressure
    2 of the four channels can be satisfied by one Reactor Vessel Water Level
  - Reactor Vessel Pressure – (Low – Permissive) – 4/4
    2 are Drywell Pressure and 2 are Reactor Vessel Pressure
    2 of the four channels can be satisfied by one Reactor Vessel Water Level
  - Injection Valve Differential Pressure (Low - Permissive) – 1/division
  - Manual – 1/division - one trip system per division

- High Pressure Coolant Injection System (1 system)
  - Reactor Vessel Water Level (Low, Low – Level 2) – 2/4
  - Drywell Pressure (High) – 2/4
  - Condensate Storage Tank Level (Low) – 1/2
  - Suppression Pool Water Level (High) -2/2
  - Reactor Vessel Water Level (High – Level 8) – 2/4
  - Manual – 1/system - one trip system with one channel

Information Supporting Instrumentation Redundancy and Diversity

2/2 is defined as two channels, two trip systems arranged in a two-out-of-two once (energize to initiate) logic, e.g., (Channel A and Channel E) or (Channel C and Channel G).

1/1 is defined as one channel, two trip systems arranged in a one-out-of-one once (energize to initiate) logic, e.g., (Channel A or Channel C)

- Automatic Depressurization System (1 system)
    - Reactor Vessel Water Level – (Low, Low, Low – Level 1)- 2/2
    - Drywell Pressure (High) – 2/2
    - ADS Timer-1/1
    - Core Spray Pump Discharge Pressure (High – Permissive) – 2/2
      Need 2 of 6 RHR or Core Spray pumps
    - RHR LPCI Mode Pump Discharge Pressure (High – Permissive) -2/2
      Need 2 of 6 RHR or Core Spray pumps
    - Reactor Vessel Water Level (Low – Level 3 – Permissive) – 1/1
    - Manual – 2/2
    - ADS Drywell Pressure Bypass Timer -2/2

    All contacts in one trip system must close except for Pump Discharge pressure permissive to initiate ADS trip system.

4. Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT)

Reference: TS 3.3.4.1 Anticipated Transient Without Scram Recirculation Pump Trip

The AWTS-RPT design creates defense-in-depth due to the redundancy of the channels for the Trip Function.

- Trip Function has multiple channels.
- Trip Function will cause an Actuation with 2/2 tripped channels.
- A failed channel does not cause or prevent a trip.

2/2 is defined as four channels, two trip systems, two channels per trip system arranged in a two-out-of-two once (energize to trip) logic, e.g., (Channel 1A and Channel 1B) or (Channel 2A and Channel 2B).

- Reactor Vessel Water Level (Low, Low – Level 2) – 2/2
- Reactor Vessel Pressure (High) – 2/2

5. End-of-Cycle Recirculation Pump Trip (EOC-RPT)

Reference: TS 3.3.4.2 End-of-Cycle Recirculation Pump Trip

The EOC-RPT design creates defense-in-depth due to the redundancy of the channels for the Trip Function.

- Trip Function has multiple channels.
- Trip Function will cause an Actuation with 2/2 tripped channels.
- A failed channel does not cause or prevent a trip.

Information Supporting Instrumentation Redundancy and Diversity

2/2 is defined as four channels, two trip systems, two channels per trip system arranged in a two-out-of-two once (energize to trip) logic, e.g., (Channel A and Channel B) or (Channel C and Channel D).

- o Turbine Stop Valve (Closure) – 2/2
- o Turbine Control Valve (Fast Closure) – 2/2

6. REACTOR CORE ISOLATION COOLING (RCIC)

Reference: TS 3.3.5 Reactor Core Isolation Cooling System Actuation

The Reactor Core Isolation Cooling design creates defense-in-depth due to the redundancy of the channels for the Initiation Function.

- Initiation Function has multiple channels.
- Initiation Function will cause an Actuation with 2/4 tripped channels.
- A failed channel does not cause or prevent an initiation.

2/4 is defined as four channels, one trip system arranged in a one-out-of-two twice (energize to initiate) logic, e.g., (Channel A or Channel C) and (Channel E or Channel G).

1/2 is defined as two channels, one trip system arranged in a one-out-of-two once (energize to initiate) logic, e.g., (Channel A) or (Channel C)

- o Reactor Vessel Water Level (Low, Low – Level 2) – 2/4
- o Reactor Vessel Water Level (High) – 2/4
- o Condensate Storage Tank Water (Low) – 1/2
- o Manual Initiation – 1/system – one trip system with one channel.

7. FEEDWATER/MAIN TURBINE TRIP SYSTEM

Reference: TS 3.3.9 Feedwater/Main Turbine Trip System Actuation

The Feedwater/Main Turbine Trip design creates defense-in-depth due to the redundancy of the channels for the Trip Function.

- Trip Function has multiple channels.
- Trip Function will cause an Isolation Actuation with 2/4 tripped channels.
- A failed channel does not cause or prevent a trip.

2/4 is defined as four channels, one trip system arranged in a one-out-of-two twice (energize to trip) logic, e.g., (Channel A or Channel C) and (Channel B or Channel D).

- o Reactor Vessel Water Level (High – Level 8) – 2/4

ENCLOSURE 1

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

<u>List of Revised Required Actions to Corresponding PRA Functions</u>

List of Revised Required Actions to Corresponding PRA Functions

1. Introduction

Section 4.0, Item 2 of the NRC Final Safety Evaluation (Reference 1 of this Enclosure) for NEI 06-09-A, Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines, Revision 0 (Reference 2) identifies the following needed content:

- The license amendment request (LAR) will provide identification of the TS Limiting Conditions for Operation (LCOs) and action requirements to which the RMTS will apply.
- The LAR will provide a comparison of the TS functions to the PRA modeled functions of the structures, systems, and components (SSCs) subject to those LCO actions.
- The comparison should justify that the scope of the PRA model, including applicable success criteria such as number of SSCs required, flow rate, etc., are consistent with licensing basis assumptions (i.e., 50.46 ECCS flowrates) for each of the TS requirements, or an appropriate disposition or programmatic restriction will be provided.

This enclosure provides confirmation that the Limerick Generating Station (LGS) PRA models include the necessary scope of SSCs and their functions to address each proposed application of the Risk-Informed Completion Time (RICT) Program to the proposed scope TS LCO Conditions, and provides the information requested for Section 4.0, Item 2 of the NRC Final Safety Evaluation. The comparison includes each of the TS LCO conditions and associated required actions within the scope of the RICT Program. The LGS PRA model has the capability to model directly or through use of a bounding surrogate the risk impact of entering each of the TS LCOs in the scope of the RICT Program.

Table E1-1 below lists each TS LCO Condition to which the RICT Program is proposed to be applied and documents the following information regarding the TSs with the associated safety analyses, the analogous PRA functions and the results of the comparison:

- Column "Proposed TS LCO Condition": Lists all of the LCOs and condition statements within the scope of the RICT Program.
- Column "SSCs Covered by TS LCO Condition": The SSCs addressed by each action requirement.
- Column "SSCs Modeled in PRA": Indicates whether the SSCs addressed by the TS LCO Condition are included in the PRA.
- Column "Function Covered by TS LCO Condition": A summary of the required functions from the design basis analyses.
- Column "Design Success Criteria": A summary of the success criteria from the design basis analyses.
- Column "PRA Success Criteria": The function success criteria modeled in the PRA.
- Column "Comments": Provides the justification or resolution to address any inconsistencies between the TS and PRA functions regarding the scope of SSCs and the success criteria. Where the PRA scope of SSCs is not consistent with the TS, additional information is provided to describe how the LCO condition can be evaluated using appropriate surrogate events. Differences in the success criteria for TS functions

are addressed to demonstrate the PRA criteria provide a realistic estimate of the risk of the TS condition as required by NEI 06-09-A, Revision 0.

The corresponding SSCs for each TS LCO and the associated TS functions are identified and compared to the PRA. This description also includes the design success criteria and the applicable PRA success criteria. Any differences between the scope or success criteria are described in the table. Scope differences are justified by identifying appropriate surrogate events which permit a risk evaluation to be completed using the Real-Time Risk (RTR) tool for the RICT program. Differences in success criteria typically arise due to the requirement in the PRA standard to make PRAs realistic rather than bounding, whereas design basis criteria are necessarily conservative and bounding. The use of realistic success criteria is necessary to conform to capability Category II of the PRA standard as required by NEI 06-09-A, Revision 0.

Examples of calculated RICT are provided in Table E1-2 for each individual condition to which the RICT applies (assuming no other SSCs modeled in the PRA are unavailable). The RICTs presented in the table are based on a Unit 1 model calculation. Due to the close similarity between the Unit 1 and Unit 2 models, the Unit 1 RICTs are considered adequate examples for the Unit 2 RICTs as well. Following 4b implementation, the actual RICT values will be calculated on a unit-specific basis, using the actual plant configuration and the current revision of the PRA model representing the as-built, as-operated condition of the plant, as required by NEI 06-09-A, Revision 0 and the NRC safety evaluation, and may differ from the RICTs presented.

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	SSCs Covered by TS LCO Condition	SSCs Modeled in PRA	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.1.5.a Only one pump and corresponding explosive valve operable	Three Standby Liquid Control pumps and two injection paths	Yes	Provide a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown	Two pumps and corresponding flow paths	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.
3.3.1.a Number of operable channels for one function in one trip system less than minimum	Four reactor protection system channels (Note 3)	Yes	Provide reactor trip signal based on plant parameters	Generally, one-out-of-two twice logic	Same	Some inputs such as loss of condenser vacuum are not modeled. Conservatively will be treated as loss of channel. (Note 3) The success criteria in the PRA are consistent with the design basis.
3.3.1.b Number of operable channels in one trip system less than minimum	See LCO Condition 3.3.1.a					
3.3.1.c Number of operable channels in both trip systems for one or more Functional Units	See LCO Condition 3.3.1.a					

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	SSCs Covered by TS LCO Condition	SSCs Modeled in PRA	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.2.b.1 Less than minimum number of channels per trip system for one trip system – tripped condition would cause an isolation	Reactor Pressure Vessel Isolation actuation instrumentation (Note 4)	Yes	Provide reactor isolation signal based on plant parameters	One of two channels	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. (Note 4) The success criteria in the PRA are consistent with the design basis.
3.3.2.b.2.a Less than minimum number of channels per trip system for one trip system – tripped condition would not cause an isolation (function common to RPS instrumentation)			See LCO Condition 3.3.2.b.1			
3.3.2.b.2.b Less than minimum number of channels per trip system for one trip system – tripped condition would not cause an isolation (function not common to RPS instrumentation)			See LCO Condition 3.3.2.b.1			

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	SSCs Covered by TS LCO Condition	SSCs Modeled in PRA	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.3.b One or more actuation instrumentation channel inoperable/ Table 3.3.3-1	ECCS actuation instrumentation (Note 6,7)	Yes	Actuation of ECCS systems (HPCI, LPCI, LPCS and ADS)	One of two channels	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. (Note 8) The success criteria in the PRA are consistent with the design basis.
3.3.3.c.1 Either ADS trip system inoperable with HPCI and RCIC operable	ECCS actuation instrumentation	Yes	Actuation of ADS	One of two channels	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.
3.3.3.c.2 Either ADS trip system inoperable with HPCI and RCIC inoperable			See LCO Condition 3.3.3.c.1			

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions						
Proposed TS LCO Condition	**SSCs Covered by TS LCO Condition**	**SSCs Modeled in PRA**	**Function Covered by TS LCO Condition**	**Design Success Criteria**	**PRA Success Criteria**	**Comments**
3.3.4.1.b. Number of operable channels one less than required	ATWS-RPT system instrumentation (Note 8)	Yes	Reduction in core power in ATWs by reduction in core flow	One of two channels	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. (Note 8) The success criteria in the PRA are consistent with the design basis.
3.3.4.1.c.1 Number of operable channels two less than required- one reactor level, one reactor pressure			See LCO Condition 3.3.4.1.b			
3.3.4.1.d One trip system inoperable			See LCO Condition 3.3.4.1.b			.
3.3.4.2.b One less than required number of channels per trip system	EOC-RPT system instrumentation (Note 5)	Yes	Reduction in core power at end of core life by reduction in core flow after reactor trip	One of two channels	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program (Note 5). The success criteria in the PRA are consistent with the design basis.

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	SSCs Covered by TS LCO Condition	SSCs Modeled in PRA	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.4.2.c.1 Two less than required number of channels per trip system – one turbine control valve channel and on turbine stop valve channel			See LCO Condition 3.3.4.2.b			
3.3.4.2.d One trip system inoperable			See LCO Condition 3.3.4.2.b			
3.3.5.b Less than required number of channels operable/ Table 3.3.5-1	RCIC actuation instrumentation	Yes	Actuation of RCIC system	One of two channels	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.
3.3.9.b One less than required number of channels operable	High water level trip instrumentation (FW and Main Turbine)	Yes	Shutdown of non-safety related turbine driven equipment prior to damage from water intrusion into the steam supply lines	One of two channels	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	SSCs Covered by TS LCO Condition	SSCs Modeled in PRA	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.3.9.c Two less than required number of channels operable	See LCO Condition 3.3.9.b					
3.4.7.a One or more MSIVs inoperable	Main steam isolation valves	Yes	Isolation of the main steam lines to minimize leakage from the containment.	One valve in each line	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.
3.5.1.a.1 One CSS subsystem inoperable with at least two LPCI subsystems operable	Two subsystems (loops) of CSS each containing two pumps and an injection path	Yes	To assure that the core is adequately cooled following a loss-of- coolant accident.	One of two loops.	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	SSCs Covered by TS LCO Condition	SSCs Modeled in PRA	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.5.1.b.4 Two LPCI subsystems inoperable	Four LPCI subsystems (trains) each containing a suppression pool suction path, pump and discharge path to the reactor vessel	Yes	To assure that the core is adequately cooled following a loss-of-coolant accident	Two of four trains	One of four trains	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis for each train. Overall PRA success criteria supported by calculations.
3.5.1.b.5 Three LPCI subsystems inoperable	See LCO Condition 3.4.1.b.4					

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions						
Proposed TS LCO Condition	**SSCs Covered by TS LCO Condition**	**SSCs Modeled in PRA**	**Function Covered by TS LCO Condition**	**Design Success Criteria**	**PRA Success Criteria**	**Comments**
3.5.1.c.1 HPCI system inoperable	HPCI system	Yes	Reactor inventory control for small break LOCA.	HPCI train	HPCI with flow through either injection path.	Calculations show that the HPCI flow rate through either the feedwater or core spray injection path is adequate. Injection only through feedwater is procedurally directed by the EOPs for certain events. SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool.
3.5.1.c.2 HPCI system and one CSS or LPCI subsystem inoperable			See LCO Condition 3.5.1.c.1			
3.5.1.d.1 One required ADS valve inoperable	ADS (5 SRVs)	Yes	Rapid reactor vessel depressurization to allow low pressure ECCS injection.	Four of five ADS SRVs	Two of five ADS SRVs	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program.

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	SSCs Covered by TS LCO Condition	SSCs Modeled in PRA	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.6.1.3.a.1 One primary containment airlock door inoperable	Primary containment airlock	Yes	Containment Integrity	One of two containment air lock doors closed.	Same	The containment airlock is explicitly modeled in the PRA and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis. .
3.6.1.3.b Primary containment airlock inoperable			See LCO Condition 3.6.1.3.a.1			
3.6.2.2.a One suppression pool spray loop inoperable	Two loops of Suppression pool spray mode of RHR	No	Steam condensation and cooling of Suppression Pool air space.	Two independent loops each consisting of one operable RHR pump	Not modeled	Suppression pool spray is not modeled in the PRA. This type of failure will be analyzed as a failure of drywell spray. This is acceptable given the connection via the downcomers of the Drywell and Wetwell airspaces

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	**SSCs Covered by TS LCO Condition**	**SSCs Modeled in PRA**	**Function Covered by TS LCO Condition**	**Design Success Criteria**	**PRA Success Criteria**	**Comments**
3.6.2.3.a One suppression pool cooling loop inoperable	Two loops Suppression pool cooling mode of RHR	Yes	Maintain the suppression pool temperature to be able to quench a reactor blowdown and remove heat from Primary Containment.	One loop	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.
3.6.2.3.a** footnote One suppression pool cooling loop inoperable for RHRSW pipe replacement			See LCO Condition 3.6.2.3.a			
3.6.3.a One or more PCIV inoperable	Primary containment isolation valves, instrumentation line excess flow check valves	Yes	Primary containment isolation	At least one isolation valve operable in each penetration	At least one isolation valve operable in each penetration. Lines less than two inches in diameter are not considered a significant leakage path	Not all valves modeled. If specific valve greater than two inches is not modeled, a generic isolation failure event will be used. This is conservative due to the remaining operable valve in the penetration.

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	**SSCs Covered by TS LCO Condition**	**SSCs Modeled in PRA**	**Function Covered by TS LCO Condition**	**Design Success Criteria**	**PRA Success Criteria**	**Comments**
3.6.4.1.a One or more vacuum breakers in one of the three required pairs of vacuum breakers inoperable for opening, but known to be closed	Suppression chamber to drywell vacuum breakers	Yes	Drywell wetwell pressure equalization	Three of four pairs	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.
3.6.5.3.a.1 (Unit 1) 3.6.5.3 a.2 (Unit 2) One train of SGTS inoperable	Two trains of SGTS	Yes	Filters secondary containment atmosphere	One of Two trains	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.
3.6.5.3 a.3 One SGTS train inoperable/ other train EDG inoperable UNIT 2 ONLY			See LCO Condition 3.6.5.3.a.1			
3.6.5.3 a.4 Both Unit 1 SGTS EDGs inoperable UNIT 2 ONLY			See LCO Condition 3.6.5.3.a.1			

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	**SSCs Covered by TS LCO Condition**	**SSCs Modeled in PRA**	**Function Covered by TS LCO Condition**	**Design Success Criteria**	**PRA Success Criteria**	**Comments**
3.7.1.1.a.2 One RHRSW pump in each subsystem inoperable	Two subsystems (loops) of RHRSW with two common pumps per loop and unit specific heat exchangers	Yes	Decay heat removal.	One pump and heat exchanger per unit	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.
3.7.1.1.a.3 One RHRSW subsystem inoperable			See LCO Condition 3.7.1.1.a.2			
3.7.1.1.a.3.a A RHRSW loop inoperable for piping replacement			See LCO Condition 3.7.1.1.a.2			
3.7.1.1.a.3.b B RHRSW loop inoperable for piping replacement			See LCO Condition 3.7.1.1.a.2			
3.7.1.1.a.6 Three RHRSW pump/diesel generator pairs inoperable (Note 1)			See LCO Condition 3.7.1.1.a.2			

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	**SSCs Covered by TS LCO Condition**	**SSCs Modeled in PRA**	**Function Covered by TS LCO Condition**	**Design Success Criteria**	**PRA Success Criteria**	**Comments**
3.7.1.2.a.3 One emergency service water loop inoperable	Two independent ESW loops (A and B), with two 50% system capacity (100% loop capacity) pumps per loop.	Yes	Supply cooling water to safety- related components, including the diesel generators, RHR pumps room coolers and chillers.	One pump per loop	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.
3.7.1.2.a.3# footnote One Emergency Service Water loop inoperable during RHRSW piping replacement			See LCO Condition 3.7.1.2.a.3			
3.7.1.2.a.4 Three ESW pump/diesel generator pairs inoperable (Note 2)			See LCO Condition 3.7.1.2.a.3			
3.7.3.a RCIC system inoperable	RCIC system	Yes	Reactor inventory control whenever the vessel is isolated from the main condenser and feedwater system.	RCIC train	Same	SSCs are modeled consistent with TS scope and so can be directly evaluated in the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis.

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	SSCs Covered by TS LCO Condition	SSCs Modeled in PRA	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.7.8 Requirements of the LCO not met or Main Turbine Bypass System inoperable	9 main turbine bypass valves	Yes	Reactor pressure control	Seven of nine turbine bypass valve	Same	Modeled as single event for less than required number available. The success criteria in the PRA are consistent with the design basis criteria.
3.8.1.1.b Two diesel generators inoperable	Four emergency diesel generators per Unit	Yes	Provide power to safety related buses when offsite power to them is lost.	Three of four diesel generators	As needed to supply supported functions.	SSCs are modeled consistent with the TS scope and so can be directly evaluated using the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis criteria.
3.8.1.1.b* footnote Two diesel generators inoperable RHRSW piping replacement			See LCO Condition 3.8.1.1.b			

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	SSCs Covered by TS LCO Condition	SSCs Modeled in PRA	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.8.1.1.d One offsite circuit and one diesel generator inoperable	Two physically independent circuits and four emergency diesel generators	Yes	Provide power to the onsite Class 1E buses.	One of two off site sources.	Same	Consistent with the TS scope and so can be directly evaluated using the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis criteria.
3.8.1.1.e.1 For two train systems, one or more diesel generators inoperable			See LCO Condition 3.8.1.1.b			
3.8.1.1.e.1* footnote For two train systems, one or more diesel generators inoperable RHRSW piping replacement			See LCO Condition 3.8.1.1.b			
3.8.1.1.f One offsite circuit inoperable			See LCO Condition 3.8.1.1.d			
3.8.1.1.g Two offsite circuits inoperable			See LCO Condition 3.8.1.1.d			

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions						
Proposed TS LCO Condition	**SSCs Covered by TS LCO Condition**	**SSCs Modeled in PRA**	**Function Covered by TS LCO Condition**	**Design Success Criteria**	**PRA Success Criteria**	**Comments**
3.8.1.1.h One offsite circuit and two diesel generators inoperable			See LCO Condition 3.8.1.1.b, d			
3.8.2.1.a.3 Restore chargers	Four DC divisions with battery and charger. Divisions 1 and 2 have 2 125VDC batteries forming a 250VDC supply. Divisions 3 and 4 have a single 125 VDC battery.	Yes	Ensure availability of required DC power to shut down the reactor and maintain it in a safe condition	Three of four DC divisions	As needed to supply supported functions.	SSCs are modeled consistent with the TS scope and so can be directly evaluated using the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis criteria.
3.8.2.1.c Any battery(ies) on one division of required DC electrical power sources inoperable	DC power sources		See LCO Condition 3.8.2.1.a			

List of Revised Required Actions to Corresponding PRA Functions

Table E1-1: In Scope TS/LCO Conditions to Corresponding PRA Functions

Proposed TS LCO Condition	SSCs Covered by TS LCO Condition	SSCs Modeled in PRA	Function Covered by TS LCO Condition	Design Success Criteria	PRA Success Criteria	Comments
3.8.3.1.a One required AC distribution system divisions not energized	Four divisions of AC power distribution systems (including the 4kV bus, 480V LC, 480 MCC, 120 V dist. panels) (Note 9)	Yes	Provide AC power to safety related systems and components	Three of four divisions	As needed to supply supported functions.	SSCs are modeled consistent with the TS scope and so can be directly evaluated using the RTR tool for the RICT Program. (Note 10) The success criteria in the PRA are consistent with the design basis criteria.
3.8.3.1.b One required DC distribution system divisions not energized	Four divisions of DC power distribution including the fuse box, distribution panel, and in some cases MCC.	Yes	Provide DC power to safety related systems and components	Three of four divisions	As needed to supply supported functions.	SSCs are modeled consistent with the TS scope and so can be directly evaluated using the RTR tool for the RICT Program. The success criteria in the PRA are consistent with the design basis criteria.

Notes:

(1) A RHRSW pump/diesel generator pair consists of a RHRSW pump and its associated diesel generator. If either a RHRSW pump or its associated diesel generator becomes inoperable, then the RHRSW pump/diesel generator pair is inoperable.

(2) An ESW pump/diesel generator pair consists of an ESW pump and its associated diesel generator. If either an ESW pump or its associated diesel generator becomes inoperable, then the ESW pump/diesel generator pair is inoperable.

List of Revised Required Actions to Corresponding PRA Functions

(3) The reactor protection system is made up of two independent trip systems (A and B). Each trip system contains 2 channels (A1, A2 and B1, B2). The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. Each channel contains the various functional inputs to RPS such Reactor level, MSIV closure, etc. Loss of any functional input does not prevent the channel from responding to other inputs. Use of a channel inoperable as a surrogate for a non-modeled functional input is conservative as it encompasses loss of all the inputs to the channel rather than any single input to the channel.

(4) Four instrumentation channels are provided to ensure protective action when required and to prevent inadvertent isolation resulting from instrumentation malfunctions. The output trip signal of each instrumentation channel initiates a trip logic. The output trip signals of the trip logics are combined in one-out-of-two-twice configuration for the MSIVs. Failure of any one trip logic does not result in an inadvertent trip. Trip logics A or C and B or D are required to initiate main steam line isolation action.
Instrumentation channels A and B or C and D are required to initiate isolation of either inboard or outboard valves, respectively. For the remaining systems. Failure of any one channel does not result in inadvertent action

(5) For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

(6) Individual pieces of instrumentation such as a pressure transmitter may be shared by multiple design basis functions

(7) The control logic for ECCS actuation, for each unit, is split into four electrical divisions (Division I, II, III, and IV). Reactor low water level (Level 1) is sensed by eight trip units in the Reactor Instrumentation System (two per Division). The trip unit outputs are connected in a one-out-of-two taken twice mixed logic to provide an automatic initiation signal
Drywell high pressure signals are sent from the Reactor Instrumentation System (RIS) to eight high drywell pressure relay contacts (two per Division). Reactor low pressure is sensed by twelve trip units in the Reactor Instrumentation System (four in Division I, four in II, two in Division III, and two in Division IV). The trip unit output relay signals are in series with the high drywell pressure signal and each such set is connected as a portion of the combined drywell high pressure and reactor low pressure initiation circuit.
The high drywell pressure relay contacts and low reactor pressure relay contacts are connected in series to provide an automatic ECCS System initiation signal.
For HPCI the low reactor water level is sensed by four trip units in the Reactor Instrumentation System. The four trip units are connected in a one-out-of-two taken twice logic to provide an automatic initiation signal.
For RCIC the low reactor water level is sensed by four trip units in the RIS. The four trip units are connected in a one-out-of-two taken twice logic to provide an automatic initiation signal.

(8) ATWS-RPT system instrumentation is part of the redundant reactivity control system and has 2 divisions each composed of two channels into which the functional inputs are fed. Both channels within a division must trip to initiate the automatic function of tripping both recirculation pumps. This is a 2-out-of-2 taken once logic. Either division can accomplish the function independently.

(9) The electrical loading of the 4KV 1E buses at Limerick Generating Station is asymmetric primarily for the loading of the common cooling water systems and HVAC systems. These systems are the Emergency Service Water (ESW) system, the Residual Heat Removal Service Water (RHRSW) system, the standby gas treatment system (SGTS) and the control room emergency fresh air system (CREFAS). The CRD and Instrument air system for each unit are also powered by 2 of the 4 divisions as they are two train systems. There are four 4KV

List of Revised Required Actions to Corresponding PRA Functions

1E buses per unit, D11, D12, D13 and D14 on Unit 1, and D21, D22, D23 and D24 on Unit 2. SGTS trains are powered by buses D11 and D12 and CREFAS by D13 and D14. ESW is powered by Unit 1 buses D11 and D12 and Unit 2 buses D23 and D24. RHRSW is powered by Unit 1 buses D11 and D12 and Unit 2 buses D21 and D22. See table below.

Unit	Unit 1				Unit 2			
Safeguard bus	D11	D12	D13	D14	D21	D22	D23	D24
System/train	0A ESW	0B ESW	Alt. 0C ESW	Alt. 0D ESW			0C ESW	0D ESW
	0A RHRSW	0B RHRSW			0C RHRSW	0D RHRSW		
	0A SGTS	0B SGTS	0A CREFAS	0B CREFAS				
	1A RERS	1B RERS			2A RERS	2B RERS		
			1A CRD	1B CRD			2A CRD	2B CRD

List of Revised Required Actions to Corresponding PRA Functions

Table E1-2: In Scope TS/LCO Conditions RICT Estimate	
TS/LCO Condition	**RICT Estimate[1,2] (days)**
3.1.5.a Only one pump and corresponding explosive valve operable	30.0
3.3.1.a Less than min. op channels for a function in one trip system	30.0
3.3.1.b Less than min. op channels for one trip system	30.0
3.3.1.c Less than min. op channels for both trip systems	30.0
3.3.2.b.1 Less than minimum number of channels per trip system for one trip system – tripped condition would cause an isolation	30.0
3.3.2.b.2.a Less than minimum number of channels per trip system for one trip system – tripped condition would not cause an isolation (function common to RPS instrumentation)	30.0
3.3.2.b.2.b Less than minimum number of channels per trip system for one trip system – tripped condition would not cause an isolation (function not common to RPS instrumentation)	30.0
3.3.3.c.1 Either ADS trip system inoperable with HPCI and RCIC operable	30.0
3.3.3.c.2 Either ADS trip system inoperable with HPCI or RCIC inoperable	30.0
3.3.4.1.b One less than min required channels	30.0
3.3.4.1.c.1 Two less than min required channels level/pressure	30.0
3.3.4.1.d One trip system inoperable	30.0
3.3.4.2.b One less than required number of channels per trip system	30.0
3.3.4.2.c.1 Two less than required number of channels per trip system – one turbine control valve channel and on turbine stop valve channel	30.0
3.3.4.2.d One trip system inoperable	30.0
3.3.5.b Less than required number of channels operable	30.0
3.3.9.b One less than required number of channels operable	30.0
3.3.9.c Two less than required number of channels operable	30.0
3.4.7.a One or more MSIVs inoperable	30.0
3.5.1.a.1 One CSS subsystem inoperable with at least two LPCI subsystems operable	30.0
3.5.1.b.4 Two LPCI subsystems inoperable	30.0
3.5.1.b.5 Three LPCI subsystems inoperable	30.0
3.5.1.c.1 HPCI system inoperable	30.0
3.5.1.c.2 HPCI system and one CSS or LPCI subsystem inoperable	30.0
3.5.1.d.1 One required ADS valve inoperable	30.0
3.6.1.3.a.1 One primary containment airlock door inoperable	30.0

List of Revised Required Actions to Corresponding PRA Functions

Table E1-2: In Scope TS/LCO Conditions RICT Estimate	
TS/LCO Condition	**RICT Estimate[1,2] (days)**
3.6.1.3.b Primary containment airlock inoperable	30.0
3.6.2.2.a One suppression pool spray loop inoperable	30.0
3.6.2.3.a One suppression pool cooling loop inoperable	30.0
3.6.2.3.a** footnote One suppression pool cooling loop inoperable RHRSW piping replacement	30.0
3.6.3.a One or more PCIV inoperable	30.0
3.6.3.b One or more instrumentation line excess flow check valves inoperable	30.0
3.6.4.1.a One or more vacuum breakers in one of the three required pairs of vacuum breakers inoperable for opening, but known to be closed	12.4 [3]
3.6.5.3.a.1 (Unit 1)/3.6.5.3.a.2 (Unit 2) One Standby Gas Treatment System (SGTS) train inoperable	30.0
3.6.5.3.a.3 (Unit 2) One SGTS train inoperable/other SGTS train Unit 1 EDG inoperable	30.0
3.6.5.3.a.4 (Unit 2) Both SGTS train Unit 1 EDGs inoperable	30.0
3.7.1.1.a.2 One RHRSW pump in each subsystem inoperable	30.0
3.7.1.1.a.3 One RHRSW subsystem inoperable	30.0
3.7.1.1.a.3.a One RHRSW subsystem inoperable	30.0
3.7.1.1.a.3.b One RHRSW subsystem inoperable	30.0
3.7.1.1.a.6 Three RHRSW pump/diesel generator pairs inoperable	30.0
3.7.1.2.a.3 One emergency service water loop inoperable	30.0
3.7.1.2.a.3# footnote One emergency service water loop inoperable RHRSW piping replacement	30.0
3.7.1.2.a.4 Three ESW pump/diesel generator pairs inoperable	30.0
3.7.3.a RCIC system inoperable	30.0
3.7.8 Requirements of LCO not met or Main Turbine Bypass System inoperable	30.0
3.8.1.1.b Two diesel generators inoperable	29.3
3.8.1.1.b* footnote Two diesel generators inoperable RHRSW piping replacement	29.3
3.8.1.1.d One offsite circuit and one diesel generator inoperable	30.0
3.8.1.1.e.1 For two train systems, one or more diesel generators inoperable	29.3
3.8.1.1.e.1* footnote for two train systems, one or more diesel generators inoperable	29.3
3.8.1.1.f One offsite circuit inoperable	30.0

List of Revised Required Actions to Corresponding PRA Functions

Table E1-2: In Scope TS/LCO Conditions RICT Estimate	
TS/LCO Condition	**RICT Estimate[1,2] (days)**
3.8.1.1.g Two offsite circuits inoperable	30.0
3.8.1.1.h One offsite circuit and two diesel generators inoperable	30.0
3.8.2.1.a.3 Two battery chargers on one division inoperable	30.0
3.8.2.1.c Any battery(ies) on one division of required DC electrical power sources inoperable	16.2
3.8.3.1.a One required AC distribution system divisions not energized	7.8
3.8.3.1.b One required DC distribution system divisions not energized	16.2

Table E1-2 Notes:

1. The RICTs presented in this table are based on a Unit 1 model calculation. Due to the close similarity between the Unit 1 and Unit 2 models, the Unit 1 RICTs are considered adequate examples for the Unit 2 RICTs as well. Following 4b implementation, the actual RICT values will be calculated on a unit-specific basis, using the actual plant configuration and the current revision of the PRA model representing the as-built, as-operated condition of the plant, as required by NEI 06-09-A, Revision 0 and the NRC safety evaluation, and may differ from the RICTs presented.

2. RICTs are based on the internal events, internal flood, and internal fire PRA model calculations with seismic CDF and LERF penalties. RICTs calculated to be greater than 30 days are capped at 30 days based on NEI 06-09-A, Revision 0. RICTs are rounded to nearest number of days or hours for illustrative purposes.

3. The limiting RICT for this TS was from the LERF calculation.

2. References

1. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,'" dated May 17, 2007 (ADAMS Accession No. ML071200238).

   Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, dated October 12, 2012 (ADAMS Accession No. ML12286A322).

ENCLOSURE 2

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Information Supporting Consistency with Regulatory Guide 1.200, Revision 2

Information Supporting Consistency with Regulatory Guide 1.200, Revision 2

1. Introduction

This enclosure provides information on the technical adequacy of the Limerick Generating Station (LGS) Probabilistic Risk Assessment (PRA) internal events model (including flooding) and the LGS fire PRA model in support of the license amendment request to revise Technical Specifications to implement NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0 (Reference 1).

Topical Report NEI 06-09-A, Revision 0 (Reference 1), as clarified by the NRC final safety evaluation of this report (Reference 2), defines the technical attributes of a PRA model and its associated Configuration Risk Management Program (CRMP), otherwise referred to as the Real-Time Risk (RTR), tool required to implement this risk-informed application. Meeting these requirements satisfies Regulatory Guide (RG) 1.174 (Reference 3) requirements for risk-informed plant-specific changes to a plant's licensing basis.

Exelon employs a multi-faceted approach to establishing and maintaining the technical adequacy and fidelity of PRA models for all operating Exelon nuclear generation sites. This approach includes both a proceduralized PRA maintenance and update process and the use of self-assessments and independent peer reviews.

Section 2 of this enclosure describes requirements related to the scope of the LGS PRA internal events model. Section 3 addresses the technical adequacy of the internal events PRA for this application. Section 4 similarly addresses the technical adequacy of the fire PRA for this application. Section 5 lists references used in the development of this enclosure.

All the PRA models described below have been peer reviewed, and the review and closure of all finding-level F&Os from the peer review have been independently evaluated to confirm that the associated model changes did not constitute a model upgrade. Sections 3 and 4 provide the disposition of all open peer review F&O findings after the closure or subsequent peer review, including the disposition of the open findings relative to this application. The resolved findings and the basis for resolution are documented in LGS PRA documentation and the Finding Closure Review reports (References 12 and 13).

2. Requirements Related to Scope of LGS PRA Models

Both the LGS internal events PRA model including internal flooding and the LGS fire PRA model are at-power models (i.e., they directly address plant configurations during plant modes 1 and 2 of reactor operation). The models include both core damage frequency (CDF) and large early release frequency (LERF). Internal flooding is included in both the CDF and LERF internal events models.

Note that this portion of the LGS PRA model does not incorporate the risk impacts of external events. The treatment of seismic risk and other external hazards for this application are discussed in Enclosure 4.

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3. Scope and Technical Adequacy of LGS Internal Events and Internal Flooding PRA Model

Topical Report NEI 06-09-A requires that the PRA be reviewed to the guidance of RG 1.200, Revision 2 (Reference 4) for a PRA which meets Capability Category (CC) II for the supporting requirements of the American Society of Mechanical Engineers (ASME) / American Nuclear Society (ANS) internal events at power PRA standard (Reference 5). It also requires that deviations from these CCs relative to the Risk Informed Completion Time (RICT) Program be justified and documented.

The information provided in this section demonstrates that the LGS internal events PRA model (including internal flood) meets the expectations for PRA scope and technical adequacy as presented in RG 1.200, Revision 2.

The LGS PRA model was subject to an NRC RG 1.200 pilot assessment in July 2004 and following the completion of the PRA model update in 2005 to strategically address the identified gaps, a peer review against the available version of the ASME PRA Standard, draft 2003 Addendum B (Reference 9) was performed in October 2005.

In May of 2008, a focused peer review of the updated Internal Flooding (IF) analysis was performed against ASME PRA Standard Revision RA-Sb-2005 (Reference 10). The IF peer review encompassed a review of the internal flood at-power PRA, consistent with the scope of the ASME PRA Standard as endorsed and clarified at the time by the NRC in RG 1.200, Revision 1 (Reference 11).

A gap assessment to the current standard, ASME/ANS RA-Sa-2009, and RG 1.200, Revision 2 has been performed. The gap assessment did not identify any deficiencies that were not identified by the peer reviews or were not previously self-identified with respect to the new standard.

The 2005 FPIE peer review findings and the 2008 internal flood peer review findings were addressed in the LGS PRA, and in July 2016 a review of the findings and the resolutions was performed by an independent Finding Closure Review team (Reference 12). Following that closure review, five findings remained open and seven partially resolved. Subsequently, the LGS FPIE PRA model was updated and most of the findings were addressed. In addition, a focused scope peer review was performed in August 2018 of a change considered an upgrade (Reference 13). The dispositions of remaining findings with respect to this application are provided in Table E2-1. Findings listed as ADDRESSED are those findings that have been addressed in the current PRA model but were not resolved by a finding closure review.

Given the resolution of the remaining partially resolved or open findings that may impact RICT calculations, the LGS internal events PRA including internal flooding will be of adequate technical capability to support the TSTF-505 program.

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Table E2-1: LGS FPIE PRA (Including Internal Flood) Findings and Disposition

Finding ID (1)	Originating SR (2)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
QU-F5-01	QU-F5 (Not Met)	Provide a discussion for the limitations of the quantification process that could impact applications (e.g., online maintenance, MPSI). One of the topics could be the WinNUPRA code limitations on the maximum number of cutsets and its impact on quantification truncation limits. (See also F&O for SY-B2.)	ADDRESSED	The LGS FPIE PRA summary and quantification notebook discusses the quantification process limitations on applications. This did not constitute an upgrade.	This was a documentation issue and does not impact RICT calculations.
QU-F6-01	QU-F6 (Not Met)	Other than for HRA, the LGS documentation does not include the applied definition of "significant". Based on the review, the definitions provided in the ASME PRA Standard appear to have been generally applied.	ADDRESSED	The definitions in the PRA Standard have been added to the PRA model documentation. This did not constitute an upgrade.	. This was a documentation issue and not impact RICT calculations.
IF-B3-01	IF-B3 Now IFSO-A5 (Not Met)	Basis for Significance: Since flood areas are documented as screened based on limited system volume, additional scenarios may need to be considered in the PRA if the system volume is considered. Discussion of Issue: Analysis of the TECW, RECW, CECW, and DWCW only considers the volume of water in the surge tank, not total system volume. Any system breach would result in gravity draining the system until level reaches that of the break. The TECW and RECW could contain significant volumes such that the scenarios may not be screened. Similarly, a break in the chilled water systems could release more water than in the surge tank. The DECW and RECW systems have automatic makeup to the surge tanks which could add water to the flood source.	ADDRESSED	The documentation and flood scenarios were reviewed and updated to address the open issues. Flood scenarios were screened based on hazard which includes a combination of flood source volume and if equipment in the area can be failed by the flood. This did not constitute an upgrade.	The documentation and flood scenarios were reviewed and updated to address the issues. Therefore, there is no impact on RICT calculations.

Table E2-1: LGS FPIE PRA (Including Internal Flood) Findings and Disposition

Finding ID (1)	Originating SR (2)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
IF-C2a-01	IF-C2a Now IFSN-A3 (Met CC I/II/III)	Basis for Significance: It appears from a review of appendices E and F that major actions needed have been identified. Discussion of Issue: No automatic actions were identified as being credited for flood termination or mitigation. Operator actions that are credited with terminating or mitigating a flooding event are generally described in Appendix E. However, the specific actions, such as, "close valve, V-XX," are not described in detail. The analyses shown in Appendix E Reference the HRA performed in Appendix F.	ADDRESSED	Appendix F of the internal flood notebook documents the operator actions credited for internal flood initiators. Appendix F provides detailed plant response, cues, location, timing, and execution information for each credited action. Appendix F references the HRA notebook which provides the HEP calculation worksheets and further details regarding HFEs. This did not constitute an upgrade.	This was a documentation issue and does not impact RICT calculations.
IF-C2b-01	IF-C2b Now IFSN-A4 (Not Met)	Basis for Significance: No specific analysis of drains appears to have been performed. Discussion of Issue: Appendix E appears to take credit for drains, however calculation of drain capacity was not evident.	ADDRESSED	The current internal flooding analysis includes a specific analysis of the drain capacity of RB-FL09, the only area where drains are credited. Section E.5 of the internal flood notebook provides a discussion of flood scenarios in Flood Zone RB-FL09. A drain capacity of 60,000 gallons was estimated and credited based on discussion with engineers and review of plant drawings. A probabilistic estimate of drainage failure is provided to address uncertainties in the drainage capacity. This did not constitute an upgrade.	The current internal flooding analysis includes a specific analysis of the drain capacity of RB-FL09, the only area where drains are credited, therefore, there will be no impact on RICT calculations.

Table E2-1: LGS FPIE PRA (Including Internal Flood) Findings and Disposition

Finding ID (1)	Originating SR (2)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
IF-C3b-01, IF-C3b-03	IF-C3b Now IFSN-A8 (Met CC I)	IF-C3b-01 Basis for Significance: Evaluation of barrier unavailability could result in significantly different flood scenarios. Evaluation of barrier unavailability is required by RG 1.200. Discussion of Issue: No consideration of barrier unavailability due to maintenance and how such unavailability could affect flood scenarios was documented. IF-C3b-03 Basis for Significance: IF-C3b requires to "IDENTIFY inter-area propagation through the normal flow path from one area to another via drain lines; and areas connected via back flow areas connected via back flow through drain lines involving through drain lines involving failed check valves, pipe and failed check valves, pipe and cable penetrations...etc.". Discussion of Issue: LG-PRA-012, section 3.3.2.1, page 3-10, first paragraph describes how the EDG rooms are independent by discussing on doors and the corridor. Drains and electrical penetrations that may exist between the EDG rooms. Also, drains between the CE, TE, and RE are not discussed.	ADDRESSED	Section 3.4.10 of internal flooding notebook documents impacts of barrier unavailability. Section 3.4.12 documents considerations of backflow in drains where credited. Section 3.4.13 documents considerations of inter-area propagation flow paths. Section 3.4.14 documents considerations of structural analysis of doors where credited. Section 2.2.11 documents considerations of backflow through drains. The analysis does not explicitly address water entering flood zones via backflow through the drain piping since there are check valves installed in the drains that service the ECCS rooms in the basement of the Reactor Enclosure that prevent propagation of water from one room to another. Also, most internal drain lines within the plant drain to the Radioactive Waste system, which was observed to have a storage capacity of over 60,000 gallons Thus, backflow through drain lines was not explicitly modeled. However, specific analysis for drain backflow or determination of the reliability of drain line check valves has been performed. This did not constitute an upgrade.	The reliability of the drain check valves and backflow have been evaluated and documented in the PRA model. Therefore, there will be no impact on RICT calculations.

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Table E2-1: LGS FPIE PRA (Including Internal Flood) Findings and Disposition

Finding ID (1)	Originating SR (2)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
IF-D1-01	IF-D1 Now IFEV-A1 (Not Met)	Basis for Significance: It appears that some internal flooding scenarios may have been associated with an inappropriate initiating event. Discussion of Issue: All flooding initiators are classified as either turbine trip or manual shutdown events as documented in Appendix D. The LGS model includes loss of service water. TECW, RECW, and AC switchgear as special initiating events. As shown in Appendix C, several service water breaks are included in the internal flooding analysis, yet it is not clear why the events, were developed as turbine trip events as opposed to loss of service water events. As discussed under SR IF-B3, flooding events involving TECW and RECW were screened based on limited system volume. When flooding involving TECW and RECW are reevaluated, this SR must be considered. The documentation does not describe why flooding events that cause a loss of switchgear are not evaluated as a loss of AC switchgear.	ADDRESSED	Consistent with the SR IFEV-A1, an evaluation of the flood sources and subsequent scenarios was performed to group the initiating events. The events are generally classified as initiators that include either a turbine trip or manual shutdown event, as appropriate, with the impact of the initiator implied to fail those SSCs that are influenced by both internal flooding and spray effects. Where necessary, sub-scenario frequencies were identified for specific components that were susceptible to nearby spray sources. That is, certain SSCs were considered vulnerable to only those nearby sources of water that could render that particular component unavailable, i.e., approximately 10 feet within a given spray source. The internal flood notebook documents the specific mapping of flood scenarios to support system initiating events where appropriate. This did not constitute an upgrade.	Mapping to support system initiators where appropriate is performed in the internal flooding analysis. Therefore, there will be no impact on RICT calculations.

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Table E2-1: LGS FPIE PRA (Including Internal Flood) Findings and Disposition

Finding ID (1)	Originating SR (2)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
IF-E1-01	IF-E1 Now IFQU-A1 (Not Met)	Basis for Significance: Since flooding events appear to be improperly categorized and no documentation of a sequence review for applicability was found, this is assigned as a Finding. Discussion of Issue: All flooding initiators are classified as either turbine trip or manual shutdown events as documented in Appendix D. The LGS model includes loss of service water. TECW, RECW, and AC switchgear as special initiating events. As shown in Appendix C, several service water breaks are included in the internal flooding analysis, yet it is not clear why the events, were developed as turbine trip events as opposed to loss of service water events. Had flooding sequences been reviewed for applicability, the appropriate accident sequence could have been associated with the proper internal initiating events group. No documentation of a sequence review was performed.	ADDRESSED	Consistent with the SR IFEV-A1, an evaluation of the flood sources and subsequent scenarios was performed to group the initiating events. The events are generally classified as initiators that include either a turbine trip or manual shutdown event, as appropriate, with the impact of the initiator implied to fail those SSCs that are influenced by both internal flooding and spray effects. Where necessary, sub-scenario frequencies were identified for specific components that were susceptible to nearby spray sources. That is, certain SSCs were considered vulnerable to only those nearby sources of water that could render that particular component unavailable, i.e., approximately 10 feet within a given spray source. . Each scenario table in Appendix D of the internal flood notebook indicates what initiator is applied (e.g., IETT, IERECW, IETMS, etc.). This did not constitute an upgrade.	Mapping to support system initiators where appropriate is performed in the internal flooding analysis. Therefore, there will be no impact on RICT calculations.
IF-E5a-01	IF-E5a Now IFQU-A6 (Not Met)	Basis for Significance: An assessment of existing HFEs is required by the standard. Discussion of Issue: No systematic assessment of the existing operator actions that are included in flood sequences was performed.	ADDRESSED	Appendix F of the current internal flooding notebook documents the flooding impact on existing HFEs and the basis for the impact. This did not constitute an upgrade.	Appendix F of the current internal flooding notebook documents the flooding impact on existing HFEs and the basis for the impact. This was a documentation issue and does not impact RICT calculations.

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Table E2-1: LGS FPIE PRA (Including Internal Flood) Findings and Disposition

Finding ID (1)	Originating SR (2)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
IF-E7-01	IF-E7 Now IFQU-A10 (Not Met)	Basis for Significance: No review of the LERF sequences for applicability was performed. Discussion of Issue: No review or quantification of flood-related LERF sequences is performed or documented.	ADDRESSED	Section 4.2, Figure 4.2, and Figure 4.4 of the internal flood notebook provide results of flood-related LERF. Flood scenarios or initiators that contribute to LERF are provided. Figure ES-2A and Figure ES-2B of the summary notebook provide flood-related contributions to total LERF. Section 6.0, Appendix G, Appendix H, and Appendix I of quantification notebook provides the LERF quantification results (including internal flood). Flood-related cutsets are provided. Sequence contributions to flood-related LERF were quantified including potential containment failure mode contributions (e.g., containment isolation, containment bypass, etc.) to flood-related LERF. This did not constitute an upgrade.	CDF and LERF results by flooding initiator are included in the internal flooding notebook. The internal flooding sequences are included in the contributions to overall results and accident sequences in the quantification and summary notebooks as part of the integrated internal events model results. This was a documentation issue and does not impact RICT calculations.

Notes to Table E2-1:

1. Each of the finding IDs that begin the characters IF are from the internal flood peer review. The other findings are from the internal events peer review.
2. The SR listed first is the applicable SR from the standard version the peer review was performed against (RA-Sb-2005, Reference 10) and the second is the applicable SR from the current standard (RA-Sa-2009, Reference 5).

4. Scope and Technical Adequacy of LGS Fire PRA Model

The LGS Fire PRA (FPRA) peer review was performed November 2011 using the NEI 07-12 Fire PRA peer review process (Reference 7), the ASME PRA Standard, ASME/ANS RA-Sa-2009 (Reference 5) and Regulatory Guide 1.200, Rev. 2 (Reference 4). The 2011 LGS FPRA peer review was a full-scope review of all of the technical elements of the LGS at-power FPRA against all technical elements in Part 4 of the ASME/ANS PRA Standard (Reference 5), including the referenced internal events supporting requirements (SRs). The findings were addressed in the LGS FPRA and in July 2016 a Finding Closure Review of the findings and the resolutions was performed by an independent review team (Reference 12). Following that review 14 of the findings were either partially resolved or still open. An additional six findings were not assessed by the independent review team since they were assessed as being open prior to the independent review. A focused scope peer review was performed in June 2017 on the implementation of the THIEF model (Reference 14). Two new findings were identified as a result if this review and are included in the listing below. In addition, a focused scope peer review of changes considered upgrades was performed in August 2018 (Reference 13). Findings listed as ADDRESSED are those findings that have been addressed in the current PRA model but were not closed by the Finding Closure Review. All open findings have been dispositioned in Table E2-2 with respect to this application.

Given the resolution of the remaining partially resolved or open findings that may impact RICT calculations, the LGS FPRA will be of adequate technical capability to support the TSTF-505 program.

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Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
1-4	ES-A2	Review of dependencies (power supply, interlock circuits and instrumentation) was not performed for components whose failure would cause an initiating event. During the peer review, three of four examples of dependency modeling were reviewed with Limerick PRA team and it was concluded that their dependencies are correctly considered. However, in other case of example, LTP94BHWI, evidence of dependency modeling was not provided to review team. It is believed that the pressure transmitter (PT-42-1N094B) needs to be supported by electrical system to perform its function, but the dependency is not included to the fire PRA logic. Furthermore, the BE's parent event (GHPC2A5) was ANDed with Div. IV gate and no power dependency is modeled under this event also. The other example was annunciation (KAN24AHWI). Generally, annunciations are supported by AC/DC power. However, review team couldn't identify any logic of power dependency of annunciations. Based on the above condition it was concluded that no systematic review of dependency was performed in Limerick fire PRA.	ADDRESSED	A systematic review was performed using the internal events model, the safe shutdown analysis, and MSO evaluations. FPRA notebooks duplicate the documentation of these evaluations that identify dependencies and how the dependency is modeled from the internal events model. These evaluations are referenced in the FPRA. This did not constitute an upgrade. The modeling of the power supply for LTP94BHWI is for HPCI Auto Initiation. Div. II DC is required for successful Auto HPCI Initiation. Therefore, the modeling of the Div. II DC power dependency is consistent with HPCI operation. This modeling approach is similar for CS. That is, the applicable division DC is required for pump operation, as well as, the Auto CS Initiation logic. Therefore, modeling the DC power dependency higher in the logic fails the pump AND auto and manual initiation. This is consistent with CS operation. The example of the annunciator (KAN24AHWI) is not modeled for fire induced failure consistent with the HRA assumptions using screening HEPs and not modeling instrumentation for non-significant actions. The annunciator event is modeled for action KHULMIDXI-F which has an F-V of ~1E-6 and a RAW of 1.	The PRA model, documentation includes the relevant information. There is no impact on RICT calculations.

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Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
2-20	PRM-C1 (SY-C2)	The FPRA documentation is not complete for the system functions and boundary, the associated success criteria, the modeled components and failure modes including human actions, and a description of modeled dependencies including support system and common cause failures, including the inputs, methods, and results. Many model changes refer back to the UREs listed in Table 2-1 of ASM-03 notebook. However, the UREs do not have the pedigree of FPIE system models and they do not meet the requirements of SR SY-C2.	ADDRESSED	The changes to the system models were made using the same methodologies that were utilized for the development of the FPIE models. The formal documentation associated with these model changes has been captured as part of the normal PRA update process. This did not constitute an upgrade.	The current Fire PRA includes documentation of this review. No impact on RICT calculations.

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Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
2-25	FSS-D7	Generic estimates per NUREG/CR-6850 are used, the system is operational during plant operation, and no outlier behavior has been identified. However, there is no documentation to verify that: a) the credited fire detection and suppression system is installed and maintained in accordance with applicable codes and standards, and b) the credited system is in a fully operable state during plant operation. Note that walkdown may be required to confirm that fire detection and suppression systems are available in the PAUs crediting such systems. Also, scope of risk relevant fire suppression and detection systems not identified.	ADDRESSED	A review of the fire protection program was performed for the fire PRA credited fire detection and suppression systems. The review included the Fire Protection System Design Baseline Document, the UFSAR Section 9.5.1 (Fire Protection program), and UFSAR Appendix 9A (Fire Protection Evaluation Report). These documents detail the design of the fire protection systems in accordance with the applicable codes. In addition, a review of program health reports for the credited fire PRA systems was performed for the fire PRA. The review concluded that the credited fire PRA fire detection and suppression systems were installed and maintained in accordance with the applicable codes and standards. Exelon procedures and the station work management processes provide the bases for establishing that the fire PRA credited systems are maintained in accordance with the applicable codes. The design change process procedure for the fire protection program assures that a proposed configuration change involving fire detection or suppression does not adversely impact the licensing basis for fire protection. The work management process prioritizes focus on fire detection or suppression systems and includes restoring inoperable systems under the station priority list. Monitoring and reporting of the effectiveness of the work management process in maintaining high levels of equipment reliability are achieved through the semi-annual health reporting metric for fire system impairments. This did not constitute an upgrade.	The current Fire PRA includes documentation of this review. No impact on RICT calculations.

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Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
2-26	FSS-D8	Several fire scenarios credited the fire detection and suppression systems. However, the effectiveness in the context of each fire scenario is not analyzed and documented. Fire detection or suppression system effectiveness depends on, at a minimum, the following: 1) system design complies with applicable codes and standards, and current fire protection engineering practice, 2) the time available to suppress the fire prior to target damage, 3) specific features of physical analysis unit and fire scenario under analysis (e.g., pocketing effects, blockages that might impact plume behaviors or the “visibility” of the fire to detection and suppression systems, and suppression system coverage), and 4) suitability of the installed system given the nature of the fire source being analyzed. The above required documentation is not evident.	ADDRESSED	The fire protection health report performance indicators worksheets for multiple years were reviewed to ensure the systems are in compliance with applicable codes and standards. The FPRA documentation was updated to include details of the assessment. The fire modeling treatments notebook documents the credited systems were assessed to be effective based on plant walkdowns and review of the fire protection program. Table 3-1 lists the systems credited and provides comments for the credited given. Entries without a specific comment are only credited in the multi-compartment analysis. That is, the credit given is only to prevent a fire progressing to an adjacent room. These systems are not credited to prevent damage in the room where the fire originates. This did not constitute an upgrade.	The current Fire PRA includes documentation for the review that was performed. No impact on RICT calculations.

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Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
2-31	CF-A1	The fire scenario notebook section 13.3 states that the risk significant basic events were identified for detailed circuit failure evaluation. A check of top scenarios, however, shows that numerous hot short failure probabilities were not set to the generic values. Based on communication with LGS risk management team, the majority of these hot short failure probabilities did not need to be incorporated into the reviewed top scenarios because either the scenario does not need to (e.g., 025_B), or the equipment has already failed with other cable failures (e.g., 013_F0E1-2). The review confirmed that LGS has performed sufficient circuit failure analysis for top risk contributors. However, the included equipment list in Table 13-2 of the FSS notebook is relatively short, which shows that not all risk significant contributors have been included. Identification of the specific components would require a detailed 'ones' run with post-processing, which was not performed for the peer review due to timing. It should be noted that the benefits to include more circuit failure analysis would be much less comparing with the listed components. On the other hand, some cables were mapped to all failure modes. For example, 1AA11509B is tied to breaker FTO, FTC and FTRC failure modes. Detailed circuit analysis should limit the failure for a particular fire scenario.	ADDRESSED	SR CF-A1 was assessed as Met CC II/III. The risk significant contributors were reviewed to ensure appropriate generic values were applied for the fire scenarios. The generic aggregate probability is the default value applied. The review identified that because no off-scheme cables are damaged in the applicable scenarios that the value is appropriate value. The review is now included in the FPRA documentation. For example, spurious events ECB0602HOI-AGG and ECB609HOI-AGG are risk significant and applicable to the most significant fire scenario. For this fire scenario the off-scheme cables are not damaged in the fire scenario. Therefore, use of the aggregate probability of 0.4 is appropriate. This did not constitute an upgrade.	The current Fire PRA includes documentation of the review. There is no impact on RICT calculations.

Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
3-4	SF-A2	The Seismic Fire Interaction and the 1995 IPEEE address the potential for spurious operation or rupture of fire suppression systems however spurious operation of detection systems is not addressed. In addition, the potential for loss of habitability due to gaseous system discharge or loss of availability due to diversion of suppressants from areas where they might be needed is not addressed. Therefore, the assessment performed in the 1995 IPEEE and accordingly the Seismic Fire Interaction Analysis does not address all of the aspects required by the standard. Accordingly, this SR is considered not met.	ADDRESSED	Section 3 and 4 of the seismic fire interactions notebook, Sections 3.1.2 and 4.1.2 discuss spurious operation of fire systems. These sections reference the new walkdowns that were performed as part of the LGS seismic PRA which are documented in the Seismic PRA walkdown notebook. This document has a discussion of seismic induced degradation or diversion of fire suppression systems and the walkdown checklists include a specific section to check for these situations. is the documentation was updated to discuss the spurious operation of detection systems. This did not constitute an upgrade.	The Seismic Fire Interaction task is a qualitative assessment. Therefore, there is no impact on RICT calculations.
4-4	CS-B1	Overcurrent coordination and protection analysis was not reviewed in detail for the FPRA. As a result, additional circuits and cables whose failure could challenge power supply availability due to inadequate or unanalyzed electrical overcurrent protective device coordination were not added to the FPRA. Additionally, power supplies credited in the FPRA using assumed cable routing did not include consideration for possible coordination issues. As a result, all areas that may impact these power supplies may not have been identified.	ADDRESSED	The FPRA documentation was updated to include details of the review of electrical overcurrent protective device coordination calculations. A detailed review of the calculations has been performed. The AC and DC electrical systems, Class 1E and non-Class 1E, are coordinated with the exception of some 208/120V panels. For these panels, the applicable cables are assumed to fail the panels in the FPRA. Additionally, the review of the calculations did not identify instances where cable length was used to show coordination. This did not constitute an upgrade.	The current Fire PRA model includes documentation of the review of electrical coordination. there is no impact on RICT calculations.

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Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
4-27	PRM-B13 (DA-A4)	The basic events added to the FPRA are documented in the UREs (e.g., see table 3-1 of ASM-03). However, the details are not provided in the FPRA documentation. For example, the SRV maintenance probability was changed from 1E-02 to 1E-03 under URE LG2011-038. However, the basis is not included in the FPRA documentation. Additionally, the basic events added in the documentation are not referenced to the UREs, and tracing each basic event to the individual UREs is difficult to perform. It is not clear from the review of the ASM notebook that all events are documented in the UREs. For example, AHUXTRDXD is listed in the HUMAN ERROR PROBABILITY FAULT TREE, but it is not clear what URE is used. Another example, JRM19BMMI0, is documented in 3.1.1.2.2 (RHRSW Loop B radiation monitor miscalibration basic event), but the basis of the event is not provided. Many of the FPRA basic events are based on failure rates, with exposure or run times. However, there is no documentation of the exposure and run times in the documentation. Overall, the basis for new basic events in the FPRA is not documented sufficient to meet the DA-A/B requirements of the standard.	ADDRESSED	The PRA documentation has been updated with the detailed information on these basic events, type codes, and associated plant specific data. This did not constitute an upgrade.	The Current Fire PRA model documentation encompasses the new basic events. Therefore, this does not impact RICT calculations.

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Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
4-33	FSS-C1	Reviewed MCA scenarios do not include detailed modeling, including the use of multiple HRRs, fire growth, decay, etc. in the analysis. For example, scenario 020_FZZ1-4 from PAU 20 to 22 (Cable spread room) assumes all PAU 20 fire scenarios (and their associated Ignition frequencies), if not suppressed, will result in a HGL in PAUs 20 and 22. These include cabinet fires, inverters and transients. In this case, the cable trays are located above several cabinets, where fairly small cabinet fires may result in overhead cable tray fires. However, additional detailed analysis could be performed to determine which cabinets would not cause this issue, calculation of the fire growth in the cabinet and cable trays, calculation of the HGL timing, analysis of the HRR for transient fires that can cause a HGL, and other steps discussed in FSS C1-8. Other MCA scenarios include HGL Severity Factors. However, it does not appear that a 2-point fire model was used, or additional factors such as growth and decay, etc.	ADDRESSED	The FPRA documentation was updated to detail the fire modeling for multi-compartment scenarios fire ignition sources which is consistent with the fire modeling performed for single compartment analyses. For an MCA scenario, the inputs for the detailed fire modeling of the exposing fire zone are used. The resolution to the example from the finding is that an MCA scenario from PAU 20 to 22 is screened since a full room damaging fire in PAU 20 leads to abandonment scenarios. The fire modeling provides the justification of the ignition sources lead to a MCA scenario. This did not constitute an upgrade.	The current Fire PRA documentation includes the contributions of ignition sources in the PAU for MCA scenarios. Therefore, there is no impact RICT calculations.

Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
4-35	FSS-G2	The MCA notebook includes both qualitative and quantitative screening criteria. The qualitative screening includes a number of scenarios where it is considered unlikely to have a large transient fire in the area. In comparing this to the Ignition frequency calculations, these areas do not have negligible transient frequencies. The qualitative argument associated with no possible transient of concern appears subjective, and basically infers an argument of a low HRR in these areas in comparison to others. However, there is little basis for this subjectivity given. Note that the recent ERIN approach for adjusting transient HRRs was recently reviewed by the Industry Fire PRA methods panel, and adjustment is possible but is required to be supported by review of transient packages possible in each area. See screening criteria 2.08 and any area with NO listed in Table A-3 of the MCA for 237 kw fires.	ADDRESSED	The MCA documentation was updated to identify the transient HRR used. The FPRA considered a range of transient HRRs. These are documented in the fire modeling treatments notebook. Transient fires of 60 kW and 145 kW are considered representative for transients in small areas that lack the space for storage and multiple pieces of equipment to perform maintenance on. This did not constitute an upgrade.	The MCA documentation was updated to identify the transient HRR used. Therefore, there is no impact on RICT calculations.
4-50	CF-A2	Methodology follows industry guidance per NUREG/CR-6850 and supplement 1. Uncertainty is qualitatively discussed. However, the uncertainty parameters for the CF probabilities is not provided in the FPRA documentation or included in the CAFTA RR file for propagation through the uncertainty calculations.	ADDRESSED	The beta uncertainty parameters from NUREG/CR-7150 Vol 2 were used to calculate the variance and applied against the type code based in the rr file for each spurious operation and duration events. Basic events were linked to the appropriate type codes. The FPRA documentation was updated. This did not constitute an upgrade.	Parametric uncertainty is explicitly addressed in the uncertainty notebook. Therefore, there is no impact on RICT calculations.

Information Supporting Consistency with Regulatory Guide 1.200, Revision 2

Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
6-8	FSS-D8	Suppression and detection effectiveness was not identified in the Fire PRA documentation.	ADDRESSED	The fire protection health report performance indicators worksheets for multiple years were reviewed to ensure that the systems are in compliance with applicable codes and standards. The FPRA documentation was updated to include details of the assessment. The credited systems were assessed to be effective based on plant walkdowns and review the fire protection program. The systems credited and when each system is credited are documented. This did not constitute an upgrade.	The current Fire PRA model documentation includes the review that was performed. No impact on RICT calculations.
6-10	FSS-E3	Individual fire modeling references generally provide qualitative uncertainty treatment and in some cases sensitivity studies. The individual fire sources are treated in the fire scenario workbook, Attachment B. Statistical representations are not provided.	ADDRESSED	The FPRA was updated to include the fire modeling parameter uncertainty. Statistical representations were provided for the scenario frequencies, non-suppression probabilities, and severity factors. This did not constitute an upgrade.	Extending the uncertainty evaluations to the fire modeling inputs for significant fire scenarios has been addressed in the current Fire PRA model. The parametric uncertainty analysis does not impact RICT calculations.
6-12	FSS-H5	Fire modeling outputs are documented in Scenario Development Report and applicable fire modeling documents. The parameter uncertainty of the output is not analyzed for each fire scenario established fire scenario as is required for Cat II.	ADDRESSED	The FPRA was updated to document the fire modeling parameter uncertainty. The finding is related to finding 6-10. This did not constitute an upgrade.	The current Fire PRA model includes this documentation. Therefore, there is no impact on RICT calculations.
FSS-D4-1	FSS-C6	Verify implementation of THIEF	ADDRESSED	Verification of expected response when compared to NUREG-1805 has been incorporated in to the Fire PRA model documentation. This did not constitute an upgrade.	The documentation the review for the verification that was performed is included in the Fire PRA model documentation. No impact on RICT calculations.

Information Supporting Consistency with Regulatory Guide 1.200, Revision 2

Table E2-2: LGS FPRA Finding Status and Disposition

Finding ID	Originating SR (1)	Finding	Status	Disposition	Impact to TSTF-505 Implementation
FSS-H5-1	FSS-H5	Lack of documentation of the uncertainty of the input parameters used for THIEF	ADDRESSED	Sensitivity studies have been performed on the input parameters showing that variation in input parameters would have a negligible effect on the fire PRA results. The results are now part of the fire PRA model documentation. This did not constitute an upgrade.	The documentation for the sensitivities that were performed is included in the Fire PRA model documentation. No impact on RICT calculations.

Notes to Table E2-2:

1. In this table finding F&Os are associated with a Part 4 SR, and if the finding F&O originated from a Part 2 SR, then the Part 2 SR is listed in parenthesis.

5. References

1. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, dated October 12, 2012 (ADAMS Accession No. ML12286A322).

2. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,'" dated May 17, 2007 (ADAMS Accession No. ML071200238).

3. Regulatory Guide (RG) 1.174, "An Approach For Using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," Revision 2, May 2011.

4. Regulatory Guide (RG) 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 2, March 2009.

5. ASME/ANS RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," Addendum A to RA-S-2008, ASME, New York, NY, American Nuclear Society, La Grange Park, Illinois, February 2009.

6. NEI 05-04, "Process for Performing PRA Peer Reviews Using the ASME PRA Standard (Internal Events)," Revision 2, September 2008.

7. NEI 07-12, "Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines," Revision 1, June 2010.

8. NUREG/CR-6850 (also EPRI 1011989), "Fire PRA Methodology for Nuclear Power Facilities," September 2005, with Supplement 1 (EPRI 1019259), September 2010.

9. "Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications," DRAFT Addendum B to ASME RA-Sa-2003, June 2005.

10. ASME RA-Sb-2005, "Addenda to ASME RA-S-2002 Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications," December 2005.

11. Regulatory Guide (RG) 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 1, January 2007.

12. JENSEN HUGHES Report 032156-RPT-001, "Limerick Generating Station PRA Finding Level Fact and Observation Technical Review," August 2016.

13. Jensen Hughes Report 032362-RPT-010, “Limerick Generating Station PRA Focused Scope Peer Review and Finding Level Fact and Observation Independent Assessment,” October 2018.

14. Limerick Generating Station Fire PRA Focused Scope Review: Use of THIEF, June 2017.

ENCLOSURE 3

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Information Supporting Technical Adequacy of PRA Models Without PRA Standards Endorsed by Regulatory Guide 1.200, Revision 2

This enclosure is not applicable to the Limerick Generating Station submittal. Exelon is not proposing to use any PRA models in the LGS Risk-Informed Completion Time Program for which a PRA standard, endorsed by the NRC in RG 1.200, Revision 2 does not exist.

ENCLOSURE 4

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

1. Introduction and Scope

Topical Report NEI 06-09-A, Revision 0 (Reference 1), as clarified by the Nuclear Regulatory Commission (NRC) final safety evaluation (Reference 2), requires that the License Amendment Request (LAR) provide a justification for exclusion of risk sources from the Probabilistic Risk Assessment (PRA) model based on their insignificance to the calculation of configuration risk as well as discuss conservative or bounding analyses applied to the configuration risk calculation. This enclosure addresses this requirement by discussing the overall generic methodology to identify and disposition such risk sources. This enclosure also provides the Limerick Generating Station (LGS) specific results of the application of the generic methodology and the disposition of impacts on the LGS Risk Informed Completion Time (RICT) Program. Section 3 of this enclosure presents the plant-specific bounding analysis of seismic risk to LGS. Section 4 of this enclosure presents the justification for excluding analysis of high wind risk to LGS. Section 5 of this enclosure presents the justification for excluding analyses of other external hazards from the LGS PRA.

Topical Report NEI 06-09-A does not provide a specific list of hazards to be considered in a RICT Program. However, non-mandatory Appendix 6-A in the ASME/ANS PRA Standard (Reference 3) provides a guide for identification of most of the possible external events for a plant site. This information was reviewed for the LGS site and augmented with a review of information on the site region and plant design to identify the set of external events to be considered. The information in the UFSAR regarding the geologic, seismologic, hydrologic, and meteorological characteristics of the site region as well as present and projected industrial activities in the vicinity of the plant were also reviewed for this purpose. The results of the review are summarized in Table E4-1 and discussed in Sections 3, 4, and 5. No new site-specific and plant-unique external hazards were identified through this review.

As explained in subsequent sections of this enclosure, risk contribution from seismic events is evaluated quantitatively, and the other external hazards listed in Table E4-1 are evaluated and screened as having low risk.

2. Technical Approach

The guidance contained in NEI 06-09-A states that all hazards that contribute significantly to incremental risk of a configuration must be quantitatively addressed in the implementation of the RICT Program. The following approach focuses on the risk implications of specific external hazards in the determination of the risk management action time (RMAT) and RICT for the Technical Specification (TS) Limiting Conditions for Operation (LCOs) selected to be part of the RICT Program.

Consistent with NUREG-1855 (Reference 4), external hazards may be addressed by:

1) Screening the hazard based on a low frequency of occurrence,
2) Bounding the potential impact and including it in the decision-making or
3) Developing a PRA model to be used in the RMAT/RICT calculation.

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

The overall process for addressing external hazards considers two aspects of the external hazard contribution to risk.

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

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

Hazard Screening

The first step in the evaluation of an external hazard is screening based on an estimation of a bounding core damage frequency (CDF) for beyond design basis hazard conditions. An example of this type of screening is reliance on the NRC's 1975 Standard Review Plan (SRP) (Reference 5), which is acknowledged in the NRC's Individual Plant Examination of External Events (IPEEE) procedural guidance (Reference 6) as assuring a bounding CDF of less than 1E-6/yr for each hazard. The bounding CDF estimate is often characterized by the likelihood of the site being exposed to conditions that are beyond the design basis limits and an estimate of the bounding conditional core damage probability (CCDP) for those conditions. If the bounding CDF for the hazard can be shown to be less than 1E-6/yr, then beyond design basis challenges from that hazard can be screened out and do not need to be addressed quantitatively in the RICT Program. The basis for this is as follows:

- The overall calculation of the RICT is limited to an incremental core damage probability (ICDP) of 1E-5.

- The maximum time interval allowed for this RICT is 30 days.

- If the maximum CDF contribution from a hazard is <1E-6/yr, then the maximum ICDP from the hazard is <1E-7 (1E-6/yr * 30 days/365 days/yr).

- Thus, the bounding ICDP contribution from the hazard is shown to be less than 1% of the permissible ICDP in the bounding time for the condition. Such a minimal contribution is not significant to the decision in computing a RICT.

The LGS IPEEE hazard screening analysis has been updated to reflect current LGS site conditions. The results are discussed in Section 5 and show that all the events listed in Table E4-1 can be screened except seismic events.

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

While the direct CDF contribution from beyond design basis hazard conditions can be shown to be non-significant using this approach, some external hazards can cause a plant challenge, even for hazard severities that are less than the design basis limit. These considerations are addressed in Section 5.

Hazard Analysis - CDF

There are two options in cases where the bounding CDF for the external hazard cannot be shown to be less than 1E-6/yr. The first option is to develop a PRA model that explicitly models the challenges created by the hazard and the role of the SSCs included in the RICT Program in mitigating those challenges. The second option for addressing an external hazard is to compute a bounding CDF contribution for the hazard. The approach used for seismic risk is described in Section 3.

Evaluate Bounding LERF Contribution

The RICT Program requires addressing both core damage and large early release risk. When a comprehensive PRA does not exist, the LERF considerations can be estimated based on the relevant parts of the internal events LERF analysis. This can be done by considering the nature of the challenges induced by the hazard and relating those to the challenges considered in the internal events PRA. This can be done in a realistic manner or a conservative manner. The goal is to provide a representative or bounding conditional large early release probability (CLERP) that aligns with the bounding CDF evaluation. The incremental large early release frequency (ILERF) is then computed as follows:

$$ILERF_{Hazard} = ICDF_{Hazard} * CLERP_{Hazard}$$

The approach used for seismic LERF is described in Section 3.

Risks from Hazard Challenges

Given the selection of an estimated bounding CDF/LERF, the approach considered must assure that the RICT Program calculations reflect the change in CDF/LERF caused by the out of service equipment. For LGS, as discussed later in this enclosure, the only beyond design basis hazard that could not be screened out is the seismic hazard, and the approach used considers that the change in risk with equipment out of service will not be higher than the bounding seismic CDF.

The above steps address the direct risks from damage to the facility from external hazards. While the direct CDF contribution from beyond design basis hazard conditions can be shown to be non-significant using these steps without a full PRA, there are risks that may be unaccounted for. These risks are related to the fact that some external hazards can cause a plant challenge even for hazard severities that are less than the design basis limit. For example, high winds, tornadoes, and seismic events can cause extended loss of offsite power conditions below design basis levels. Additionally, depending on the site, external floods can challenge the availability of normal plant heat removal mechanisms.

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The approach taken in this step is to identify the plant challenges caused by the occurrence of the hazard within the design basis and evaluate whether the risks associated with these events are either already considered in the existing PRA model or they are not significant to risk.

Section 3 of this enclosure provides the analysis for the LGS site with respect to the beyond design basis seismic hazard, and Section 4 provides an analysis for the extreme winds hazard. Section 5 of this enclosure provides an analysis of the representative external hazards for the LGS site.

3. Seismic Bounding Analysis

This section presents the analysis that bounds the potential seismic impact for inclusion in the decision-making process, as a seismic PRA is not available for LGS. The process for analyzing an unscreened external hazard without the use of a full PRA involves the following three steps:

1. Estimate Bounding CDF
2. Evaluate Potential Risk Increases Due to Out of Service Equipment
3. Evaluate Bounding LERF Contribution

Estimate Seismic CDF

A seismic PRA (SPRA) is not available for LGS. LGS submitted a Seismic Margins Assessment (SMA) in its Individual Plant Examination for External Events (IPEEE) (Reference 7), as permitted by NRC NUREG-1407 (Reference 6). Therefore, an alternative approach is taken to provide an estimate of seismic core damage frequency (SCDF) based on the current LGS seismic hazard curve and assuming the seismic capacity of a component whose seismic failure would lead directly to core damage. This approach to estimation of the SCDF uses a plant level high confidence of low probability of failure (HCLPF) seismic capacity and convolves the corresponding failure probabilities as a function of seismic hazard level with the seismic hazard curve. This is a commonly used approach to estimate SCDF when a seismic PRA is not available. This approach is consistent with approaches that have been used in other regulatory applications.

The seismic hazard for the LGS site was evaluated in 2013 (Reference 8) and provided to NRC via Reference 9. The LGS IPEEE assessed LGS structures, systems and components (SSCs) associated with LGS SMA success paths to a review level earthquake (RLE) value of 0.15g. However, through Request for Additional Information (RAI) exchanges with the NRC, the LGS SSCs included in the SMA were reassessed at the RLE level of 0.3g. The NRC's safety evaluation report (SER, Reference 10) associated with LGS IPEEE acknowledged that all SSCs on the success path component list (SPCL) have a capacity of at least 0.3g PGA or are acceptable as-is. Therefore, the plant level HCLPF value of 0.3g PGA is utilized to determine sufficiently bounding SCDF and SLERF estimates for LGS in this submittal. Calculation of the SCDF in this manner also requires definition of uncertainty parameters for seismic capacity. The uncertainty parameter for seismic capacity is represented by a composite beta factor (βc) of 0.4. This is a commonly-accepted approximation and is consistent with the value used in Reference 11. Using the above inputs, the total estimated LGS SCDF is determined to be 3.7E-06 for the IPEEE (0.3g PGA) HCLPF. This SCDF value will be used as the bounding estimate of instantaneous SCDF ($ICDF_{Seismic}$) for the TSTF-505 submittal RICT calculations.

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Evaluate Potential Risk Increases Due to Out of Service Equipment

The approach taken in the computation of SCDF assumes that the SCDF can be based on the likelihood that a single seismic-induced failure leads to core damage. This approach is bounding and implicitly relies on the assumption that seismic-induced failures of equipment show a high degree of correlation (i.e., if one SSC fails, all similar SSCs will also fail). This assumption is conservative, but direct use of this assumption in evaluating the risk increase from out of service equipment could lead to an underestimation of the change in risk. However, if one were to assume no correlation at all in the seismic failures, then the seismic risk would be lower than the risk predicted by a fully correlated model, but the change in risk using the un-correlated model with a redundant piece of important equipment out of service would be equivalent to the level predicted by the correlated model.

If the industry accepted approach (Reference 12) of correlation is assumed, the conditional core damage frequency given a seismic event will remain unaltered whether equipment is out of service or not. Thus, the risk increase due to out of service equipment cannot be greater than the total SCDF estimated by the bounding method used in Reference 12. That is, for the LGS site, the delta SCDF from equipment out of service cannot be greater than 3.7E-6/yr (Reference 13).

To summarize the above considerations:

- The baseline seismic risk in this approach is assumed to be zero, whereas there will always be some level of baseline seismic risk for a zero-maintenance plant configuration. Therefore, the incremental seismic risk (configuration seismic risk – baseline seismic risk) will always be overstated using a seismic penalty based on the total estimated seismic risk.

- The limiting HCLPF approach assumes that a failure of a component with seismic capacity at that HCLPF leads directly to core damage (CD). However, even common failure of a given set of components (e.g., all emergency diesel generators (EDGs)) would not lead directly to CD, especially in light of the post-Fukushima FLEX mitigating strategies now in place. In reality, there are few SSCs whose failure would lead to seismic CD with any significant frequency. Examples could be important structures, or the reactor pressure vessel, or "distributed systems" such as all cable trays or all piping systems. Such failures involve HCLPFs much higher than the 0.3g value assumed for the bounding calculation.

- In a seismic PRA, seismic impacts to similar components (e.g., all the EDGs) are typically assumed to be correlated unless there are reasons to justify not correlating. Correlation has the effect of introducing common cause impacts. So, if one train of emergency AC power fails seismically, both trains are modeled as likely to fail given the same seismic event. So, in general, most seismic impacts would effectively be equivalent to TS loss of function.

- Given the above, the use of a seismic penalty based on assuming seismic core damage given the plant level HCLPF is appropriate.

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Note that there is another significant conservatism inherent in this approach in addition to the above considerations. In determining the SCDF to be used in the RICT calculations, the full annual seismic hazard has been used. Since the maximum RICT backstop is 30 days, accounting for the full hazard introduces more than a factor of 10 increase in the calculated SCDF.

Evaluate Seismic LERF Contribution

The current LGS internal events PRA (Reference 14) includes a comprehensive treatment of LERF due to internally initiated events. The internal events PRA provides an estimate of the conditional probability of LERF for each modeled initiating event. Seismic events would not be expected to induce containment bypass scenarios, e.g., Interfacing Systems Loss of Coolant Accident (ISLOCA) or Break Outside of Containment (BOC), and the bypass resulting from ISLOCA or BOC is not a function of containment seismic capability. Therefore, a bounding conditional large early release probability for seismic events ($CLERP_{Seismic}$) can be obtained by examining the event-specific CDF and event-specific LERF, for the non-direct bypass events, i.e.,

$$CLERP_{IE} = LERF_{IE} / CDF_{IE}$$

Using the current LGS internal events PRA, the average CLERP over all initiating events other than direct containment bypass events is approximately 6% (Reference 13). However, a number of initiating events result in CLERP values greater than 6%. A LERF-weighted average CLERP can be computed for each initiating event as follows:

$$CLERP_{\text{weighted event i}} = CLERP_{\text{event i}} \times [LERF_{\text{event i}} / \text{Total LERF}]$$

The overall weighted CLERP is the sum of the event CLERP values. The weighted CLERP calculated for the LGS internal events at power model results other than direct containment bypass events, including the events with CLERP values above the average CLERP, is 0.16.

Several initiating events having FPIE CLERP values above the average 6% value (and above the weighted CLERP value) are not pertinent to the seismic CLERP calculation. These are discussed as follows:

- Large LOCA Above TAF (%A-STEAM) with CLERP = 0.49: NSSS SSCs generally have a high seismic capacity such that the seismic induced Large LOCA contribution to LERF is likely not significant. So, the CLERP for this event should not apply to the determination of the seismic CLERP.
- Large LOCA Below TAF (%A-WATER) with CLERP = 0.44: Based on the discussion for Large LOCA Above TAF scenarios, a CLERP of 0.44 would not apply to the dominant seismic CDF scenarios.
- Manual Shutdown (%TMS) with CLERP = 0.32: Based on a review of plant specific operating experience, Manual Shutdown events at LGS often coincide with a planned

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shutdown where the primary containment has been intentionally de-inerted (e.g., prior to a refuel outage). Given the high probability for a de-inerted primary containment during manual shutdown events, subsequent core damage events have a high CLERP due to the increased potential for hydrogen deflagration events. A CLERP of 0.32 is from the average annual model and includes a fraction of time de-inerted. Based on plant practices, this fractional time frame is higher for manual shutdown events than for other initiators. For the RICT calculations, the actual configuration representing the de-inerted condition will be specified in the CRM model. This will lead to higher instantaneous CLERP values for all initiating events. A CLERP of 1.0 can conservatively be assumed for time frames of de-inerted conditions to determine the seismic penalty (i.e., SLERF = SCDF when de-inerted). Since de-inerted conditions are rare and typically occur just before and just after refueling outages, the increased seismic penalty does not need to be included in the RICT calculations.

- Turbine Trip (%TT) with CLERP = 0.27: This is primarily due to the contribution of TT ATWS events. Turbine Trip is not reflective of SPRA accident sequences. The scram function in BWRs has a high median seismic capacity, such that seismic induced ATWS would have only a small contribution in a seismic PRA. Thus, the FPIE model CLERP for this event is not representative for the seismic CLERP calculation.

- IORV Transient (%TI) with CLERP = 0.26: Safety relief valve are seismically rugged components such that IORV/SORV (stuck open relief valve) scenarios would not be significant seismic risk contributors. Thus, the FPIE model CLERP for this event is not representative for the seismic CLERP calculation. Further, the %TI event is a very small contributor to the overall FPIE CDF and LERF, and so is not representative of a CLERP to be used for the seismic RICT contribution.

There are numerous internal flood scenarios that each have small CDF and LERF contributions but have relatively high CLERP values. The total CDF for the internal flood scenarios with an internal events CLERP > 0.2 (i.e., just above the weighted CLERP value) is approximately 4E-8, or just over 1% of total FPIE CDF. The total LERF for the internal flood scenarios with an internal events CLERP > 0.2 is approximately 9E-9, or just under 5% of total FPIE LERF. Since these sequences together represent a small contribution to the overall FPIE CDF and LERF, the associated CLERP values are not representative of a CLERP to be used for the seismic RICT contribution.

Based on the above discussion, a 20% value of CLERP is chosen as an adequately conservative but not overly pessimistic estimate for use in the seismic induced LERF calculation. This encompasses those internal events initiators contributing over 90% of total LERF and over 95% of total CDF for those events not discussed in the bullets above.

The incremental bounding large early release frequency from seismic events (i.e., the SLERF) for use in RICT calculations is then computed as:

$$ILERF_{Seismic} = ICDF_{Seismic} * CLERP_{Seismic} = 3.7E\text{-}6 * 0.2 = 7.4E\text{-}7$$

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This value of 7.4E-07 will be used for base case SLERF value for RICT calculations that apply to plant conditions when primary containment is inerted.

If a RICT is being entered during an infrequently encountered period when the containment is not inerted, a conservative CLERP multiplier of 1.0 will be applied to address the increased potential for hydrogen deflagration events.

Since this estimation of CLERP may change as the internal events PRA model is updated, the estimate will be updated for the RICT program with each internal events model update.

Conclusion

The above analysis provides the technical basis for addressing the seismic-induced core damage risk for LGS by reducing the ICDP/ILERP criteria to account for a bounding estimate of the configuration risks due to seismic events.

The RICT and RMAT calculations are based the discussion provided above. The actual RICT and RMAT calculations performed by the LGS Configuration Risk Management Tool are based on adding an incremental 3.7E-6/year seismic CDF contribution and corresponding 7.4E-7/year (or 3.7E-06/year when containment is not inerted) seismic LERF contribution to the configuration-specific delta CDF and delta LERF attributed to internal and fire events contributions. This is accomplished by adding these seismic contributions to the instantaneous CDF/LERF whenever a RICT is in effect. This method ensures that an incremental seismic CDF/LERF equal to the bounding SCDF/SLERF is added to internal and fire events incremental CDF/LERF contribution for every RICT occurrence.

4. Extreme Winds Analysis

Section 3.3 of the LGS UFSAR (Reference 15) describes the capability of safety related structures to withstand wind and tornado loadings. Structures that directly affect the ultimate safe shutdown of the plant are designed to resist applicable design basis tornado forces, which bound other winds. The design basis tornado considers the forces associated with 300 mph winds applied over an entire structure. Per Table 6-1 of NUREG/CR-4461, Rev. 2 (Reference 16), the 10^{-7} probability tornado wind speed is 256 mph, based on the F-scale, and 202 mph, based on the more recent EF-scale.

For the Limerick site, high wind effects from sources other than tornadoes (e.g., hurricanes and straight winds) are less severe than for tornadoes and are thus bounded by the tornado hazard.

Section 3.5.1.4 of the LGS UFSAR (Reference 15) describes the capability of safety related structures to protect SSCs against tornado missiles and protection of the ESW and RHRSW system yard piping by burial. LGS is in conformance with Regulatory Guide 1.117 regarding systems to be protected from tornado missiles, except for unprotected parts of the ESW and RHRSW systems and spray pond networks. For these SSCs, a hazard analysis was performed in 1984 to determine the likelihood of the loss of ultimate heat sink (UHS), i.e., ESW and RHRSW by tornados and tornado missiles (Reference 17).

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

The hazard analysis, reviewed by the NRC (Reference 18), showed that the likelihood of a loss of all UHS was approximately 8E-7/yr. A comparison was made of tornado frequencies used in the 1984 PRA and those based on data from NUREG/CR-4461, Rev. 2 (Reference 16). The comparison shows that estimated tornado frequencies have been reduced by more than a factor of 10 from the 1984 analysis. Thus, the loss of UHS due to tornadoes and tornado missiles is estimated to be less than 1E-6/yr (Reference 19). The PRA shows that the only damage is from F4 and greater tornadoes (≥206 mph). The high wind ('straight wind') and hurricane frequencies are negligible (i.e., much less than 1E-7/yr) at these wind speeds. Additionally, the risk associated with UHS maintenance configurations, allowed by TS, was evaluated and can also be screened. Therefore, these events will not significantly impact RICT calculations and can be excluded from further consideration. Therefore, the total frequency for wind speeds of concern is essentially equal to the tornado frequency.

Therefore, high winds and their effects can be screened from consideration in the RICT program.

5. Evaluation of External Event Challenges and IPEEE Update Results

The primary purpose of this section is to address the incremental risk associated with challenges to the facility that do not exceed the design capacity. This section also provides results of the hazard screening described earlier. Seismic events are the only hazards not screened out. Table E4-1 lists the external hazards considered.

Hazard Screening Except Seismic Events

The LGS IPEEE for Units 1 and 2 (Reference 7) provides an assessment of the risk to LGS associated with these hazards. Additional analyses have been done since the IPEEE to provide updated risk assessments of various hazards, such as aircraft impacts, industrial facilities and pipelines, and external flooding. These analyses are documented in the UFSAR (Reference 15).

Table E4-1 reviews the bases for the evaluation of these hazards, identifies any challenges posed, and identifies any additional treatment of these challenges, if required. Table E4-2 provides the criteria applied in the progressive screening process used in this assessment. The conclusions of the assessment, as documented in Table E4-1, assure that the hazard either does not present a design-basis challenge to LGS, or is adequately addressed in the PRA.
External hazards other than seismic can be screened for the LGS site.

In the application of Risk-Informed Completion Times, a significant consideration in the screening of external hazards is whether particular plant configurations could impact the decision on whether a particular hazard that screens under the normal plant configuration and the base risk profile would still screen given the particular configuration. The external hazards screening evaluation for Limerick has been performed accounting for such configuration-specific impacts. The process involves several steps.

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

As a first step in this screening process, hazards that screen for one or more of the following criteria (as defined in Table E4-2) still screen regardless of the configuration, as these criteria are not dependent on the plant configuration.

- The occurrence of the event is of sufficiently low frequency that its impact on plant risk does not appreciably impact CDF or LERF. (Criterion C2)
- The event cannot occur close enough to the plant to affect it. (Criterion C3)
- The event which subsumes the external hazard is still applicable and bounds the hazard for other configurations (Criterion C4)
- The event develops slowly, allowing adequate time to eliminate or mitigate the hazard or its impact on the plant. (Criterion C5)

The next step in the screening process is to consider the remaining hazards (i.e., those not screened per the above criteria) to consider the impact of the hazard on the plant given particular configurations for which a RICT is allowed. For hazards for which the ability to achieve safe shutdown may be impacted by one or more such plant configurations, the impact of the hazard to particular SSCs is assessed and a basis for the screening decision applicable to configurations impacting those SSCs is provided.

As noted above, the configurations to be evaluated are those involving unavailable SSCs whose LCOs are included in the RICT program.

Seismic-Induced Loss of Offsite Power Challenges

For the LGS site, the only incremental risk associated with challenges to the facility that do not exceed the design capacity, which is not already addressed, is the seismically-induced LOOP. The methodology for computing the seismically-induced LOOP frequency is simply a convolution of the mean seismic hazard curve and the offsite power fragility. The LGS seismic hazard curve is as described in Reference 9.

Table E4-3 provides the mean seismic hazard, represented by a series of discrete seismic hazard intervals from just below the LGS operating basis earthquake to significantly above the safe shutdown earthquake, and the LOOP failure probability for each seismic interval based on the fragility of offsite power, represented by failure of ceramic insulators in the offsite power switchyard. The failure probabilities are based on the fragility data from Table 4-3 of the RASP Handbook (Reference 20):

Median Offsite Power Capacity = 0.35g, β_R = 0.39, β_U = 0.39

Given the mean frequency and failure probability for each seismic hazard interval, the estimated frequency of seismically induced loss of offsite power for the LGS site is obtained by taking the product of the interval frequency and the offsite power failure probability. As shown in Table E4-3, the total seismic LOOP frequency is the sum of interval frequencies, or 2.7E-5/yr.

The internal events PRA models LOOP from plant-centered, switchyard-centered, grid-related, and weather-related events. Based on the LGS internal events PRA, total frequency of unrecovered

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

loss of offsite power, i.e., the sum of the frequency times the non-recovery probability at 24 hours over these LOOP events, is 1.9E-03/yr (Reference 13).

The seismically-induced (unrecoverable) LOOP frequency is therefore less than 2% of the total unrecovered LOOP frequency that is already accounted for in the internal events PRA. This frequency is judged to be a sufficiently small fraction that it will not significantly impact the RICT Program calculations and it can be omitted.

Table E4-1: Evaluation of Risks from External Hazards

External Hazard	Screened? (Y/N)	Screening Criterion (Note a)	Disposition for RICT
Aircraft Impact	Y	C2 PS2 PS4	The Limerick UFSAR explicitly analyzes the probability of an aircraft impact on site in Section 3.5.1.6. This analysis applies data (described in UFSAR Section 2.2.2) on commercial air traffic from federal airways, local airports, and the on-site heliport. The analysis indicates that the site risk due to aircraft impact events is dominated by takeoff/landing events associated with local airports and the on-site heliport. As a result, the aircraft impact hazard screens via criterion C2 for commercial air traffic from federal airways and criteria PS2 and PS4 for unacceptable consequences for air traffic associated with local airports / site heliport. Therefore, this hazard can be excluded from the RICT Program evaluation.
Avalanche	Y	C3	Not applicable to the site because of climate and topography.
Biological Event	Y	C3 C5	Sudden influxes not applicable to the plant design (closed loop systems). Slowly developing growth can be detected and mitigated by surveillance. Therefore, this hazard can be excluded from RICT Program evaluation.
Coastal Erosion	Y	C3	Not applicable to the site because of location.
Drought	Y	C5	Plant design eliminates drought as a concern and event is slowly developing. Therefore, this hazard can be excluded from RICT Program evaluation.
External Flooding	Y	C1	The external flooding hazard at the site was recently updated as a result of the post-Fukushima 50.54(f) Request for Information and the flood hazard

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

Table E4-1: Evaluation of Risks from External Hazards			
External Hazard	**Screened? (Y/N)**	**Screening Criterion (Note a)**	**Disposition for RICT**
			reevaluation report (FHRR) was submitted to NRC for review on March 12, 2015 (Reference 21). The results indicate that flooding from rivers and streams (precipitation based) and dam failure are bounded by the current licensing basis (CLB) and do not pose a challenge to the plant. Flooding from local intense precipitation was evaluated and will not challenge any safety functions at Limerick.
Extreme Wind or Tornado	Y	C1 PS4	Capability of SSCs to withstand wind and tornado loadings is discussed in Section 3.3 and 3.5.1.4 of the Limerick UFSAR. The risk due to extreme winds and tornados is small. Section 3.3 of the Limerick UFSAR describes the capability of safety related structures to withstand wind and tornado loadings. The design basis tornado was reviewed against Table 6-1 of NUREG/CR-4461, Rev. 2, and was found to be bounding. Therefore, no additional considerations were necessary. Section 3.5.1.4 of the Limerick UFSAR describes the capability of safety related structures to protect SSCs against tornado missiles. A comparison was made of tornado frequencies used in the current design basis and those based on data from NUREG/CR-4461, Rev. 2. The comparison showed that estimated tornado frequencies have been reduced by more than a factor of 10 from the original design basis. Thus, the loss of ability to safely shut down the plant due to tornadoes and tornado missiles is estimated to be very small." Therefore, extreme winds/tornadoes will have no impact on RICT and can be excluded from RICT Program evaluation. Additionally, the risk associated with Ultimate Heat Sink maintenance configurations, allowed by TS, was evaluated and can also be screened. Therefore, these events will not significantly impact RICT calculations and can be excluded from further consideration.

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

Table E4-1: Evaluation of Risks from External Hazards			
External Hazard	**Screened? (Y/N)**	**Screening Criterion (Note a)**	**Disposition for RICT**
Fog	Y	C1	Negligible impact on the plant.
Forest or Range Fire	Y	C3	Not applicable to the site because of limited vegetation.
Frost	Y	C1	Negligible impact on the plant and occurrence of event is predictable.
Hail	Y	C1 C4	Limited occurrence and bounded by other events for which the plant is designed. Flooding impacts covered under intense precipitation (see External Flooding). Therefore, it can be excluded from RICT Program evaluation.
High Summer Temperature	Y	C1 C4	Plant is designed for this hazard. Associated plant trips are rare and are covered in the definition of another event in the PRA model (e.g., transients, loss of condenser). Therefore, it can be excluded from RICT Program evaluation.
High Tide, Lake Level, or River Stage	Y	C1 C3	High tide or lake level not applicable to the site because of location. Impact of high river stage is slow to develop.
Hurricane	Y	C4	Covered under Extreme Wind or Tornado and Intense Precipitation (see External Flooding).
Ice Cover	Y	C1 C3	Negligible impact to the site. Ice blockage causing flooding is not applicable to the site because of location. Plant is designed for freezing temperatures, which are infrequent and short in duration. The plant procedure for severe weather and natural disasters includes attachments for Schuylkill river pump house icing (normal makeup to cooling tower) and addresses ESW system winter bypass. Therefore, it can be excluded from RICT Program evaluation.
Industrial or Military Facility Accident	Y	C1 C3	Explosive hazard impacts and control room habitability impacts meet the 1975 SRP requirements (Regulatory Guides 1.78 and 1.91) (References 22 and 23, respectively). In addition, UFSAR Section 2.2.3 discusses the impact of industrial and military facilities on the site.

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

Table E4-1: Evaluation of Risks from External Hazards			
External Hazard	**Screened? (Y/N)**	**Screening Criterion (Note a)**	**Disposition for RICT**
			There are no military facilities within 5 miles of the site. There are no industrial activities involving explosive storage near the site. Other potential hazards are evaluated elsewhere in this table (e.g., transportation accidents). Therefore, they can be excluded from RICT Program evaluation.
Internal Flooding	N	None	The LGS Internal Events PRA includes evaluation of risk from internal flooding events
Internal Fire	N	None	The LGS Internal Fire PRA addresses risk from internal fire events
Landslide	Y	C3	Not applicable to the site because of topography.
Lightning	Y	C1	Lightning strikes causing loss of offsite power or turbine trip are contributors to the initiating event frequencies for these events, which are already modeled in the LGS internal events PRA.
Low Lake Level or River Stage	Y	C3 C5	Low lake level not applicable to the site because of location. Impacts of low river stage event are slow to develop.
Low Winter Temperature	Y	C1 C5	The plant is designed for extended freezing events, and their impacts are slow to develop. See also ice cover.
Meteorite or Satellite Impact	Y	PS4	Negligible impact to the site. The frequency of meteorites greater than 100 lbs. striking the plant is around 1E-8/y and corresponding satellite impacts is around 2E-9/y (Reference 24). Therefore, they can be excluded from RICT Program evaluation.
Pipeline Accident	Y	C1	The plant is designed for such peak pressures from explosion of nearby pipelines per UFSAR Section 2.2.3.1.1. Therefore, they can be excluded from RICT Program evaluation.

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

Table E4-1: Evaluation of Risks from External Hazards			
External Hazard	**Screened? (Y/N)**	**Screening Criterion (Note a)**	**Disposition for RICT**
Release of Chemicals in Onsite Storage	Y	C4 PS1	UFSAR Section 2.2.3.1.3 discusses onsite chemical storage. Detection and isolation capability is provided for chemicals constituting a hazard for the control room. Other spills were determined to have no adverse effects on operation of plant equipment. See also Transportation Accidents.
River Diversion	Y	C3 C5	Not applicable to the site because of location. Diversion of the Schuylkill River would be a very slowly developing impact.
Sand or Dust Storm	Y	C1 C5	The plant is generally not vulnerable to such events due to location. In any case, the plant is designed for such events, and a procedure instructs operators to replace filters before they become inoperable.
Seiche	Y	C1 C3	Not applicable to the site because of location.
Seismic Activity	N	None	Seismic impacts evaluated in terms of bounding seismic penalty on Risk Informed Completion Times (RICT). See section 3 of this enclosure.
Snow	Y	C1 C4	The event damage potential is less than other events for which the plant is designed. Potential flooding impacts covered under external flooding. The Plant procedure for severe weather and natural disaster guidelines includes an attachment for Snow. Therefore, it can be excluded from RICT Program evaluation.
Soil Shrink-Swell Consolidation	Y	C1 C5	The potential for this hazard is low at the site, the plant design considers this hazard, and the hazard is slowly developing and can be mitigated.
Storm Surge	Y	C3	Not applicable to the site because of location.
Toxic Gas	Y	C4	Toxic gas covered under release of chemicals in onsite storage, industrial or military facility accident, and transportation accident.

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

Table E4-1: Evaluation of Risks from External Hazards

External Hazard	Screened? (Y/N)	Screening Criterion (Note a)	Disposition for RICT
Transportation Accident	Y	C3 C4 PS2 PS4	Typical truck tanker volume of eighteen chemicals potentially transported via State Route 422 (listed in Regulatory Guide 1.78) were evaluated to determine the significance of the threat to the control room envelope. None of the calculations for the chemicals fall above the limits given in Regulatory Guide 1.78. Reference 25 also identifies two chemicals that are transported via railway more than 30 times a year (Benzene and Butane). These chemicals were both determined to not impact main control room habitability per analyses of Regulatory Guide 1.78, so they can be excluded from RICT Program evaluation. Section 2.2.3.1.1 of the UFSAR contains an analysis of accidents on the nearby railway line, highways, or pipelines. The plant is designed to withstand such accidents.
Tsunami	Y	C3	Not applicable to the site because of location.
Turbine-Generated Missiles	Y	PS2 PS4	Turbine Generated Missiles are evaluated in UFSAR Section 3.5.1.3. The probability of unacceptable damage from turbine missile is maintained at less than or equal to 1x10-7 per year. Therefore, they can be excluded from RICT Program evaluation.
Volcanic Activity	Y	C3	Not applicable to the site because of location.
Waves	Y	C3	Waves associated with adjacent large bodies of water are not applicable to the site. Waves associated with external flooding are covered under that hazard.
Note a: See Table E4-2 for descriptions of the screening criteria.			

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

Table E4-2: Progressive Screening Approach for Addressing External Hazards

Event Analysis	Criterion	Source	Comments
Initial Preliminary Screening	C1. Event damage potential is < events for which plant is designed.	NUREG/CR-2300 (Reference 26) and ASME/ANS Standard RA-Sa-2009 (Reference 3)	
	C2. Event has lower mean frequency and no worse consequences than other events analyzed.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	
	C3. Event cannot occur close enough to the plant to affect it.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	
	C4. Event is included in the definition of another event.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	Not used to screen. Used only to include within another event.
	C5. Event develops slowly, allowing adequate time to eliminate or mitigate the threat.	ASME/ANS Standard RA-Sa-2009	
Progressive Screening	PS1. Design basis hazard cannot cause a core damage accident.	ASME/ANS Standard RA-Sa-2009	
	PS2. Design basis for the event meets the criteria in the NRC 1975 Standard Review Plan (SRP) (Reference 16).	NUREG-1407 (Reference 6) and ASME/ANS Standard RA-Sa-2009	
	PS3. Design basis event mean frequency is < 1E-5/y and the mean conditional core damage probability is < 0.1.	NUREG-1407 as modified in ASME/ANS Standard RA-Sa-2009	
	PS4. Bounding mean CDF is < 1E-6/y.	NUREG-1407 and ASME/ANS Standard RA-Sa-2009	

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

Table E4-2: Progressive Screening Approach for Addressing External Hazards			
Event Analysis	**Criterion**	**Source**	**Comments**
Detailed PRA	Screening not successful. PRA needs to meet requirements in the ASME/ANS PRA Standard.	NUREG-1407 and ASME/ANS Standard RA-Sa-2009	

Table E4-3: Seismic LOOP Frequency Estimate					
Acceleration (g)	**Seismic Interval (g)**	**Interval Representative g Level**	**Interval Frequency (/yr)**	**Offsite Power Failure Prob.**	**Seismic Interval LOOP Frequency**
0.075	0.075 - 0.3	0.15	2.18E-04	6.22E-02	1.35E-05
0.3	0.3 - 0.5	0.39	1.31E-05	5.73E-01	7.48E-06
0.5	0.5 - 0.7	0.59	3.20E-06	8.29E-01	2.65E-06
0.7	0.7 - 0.9	0.79	1.57E-06	9.31E-01	1.47E-06
0.9	0.9 - 1.1	0.99	6.73E-07	9.71E-01	6.54E-07
1.1	1.1 - 1.3	1.20	3.15E-07	9.87E-01	3.11E-07
1.3	1.3 - 1.5	1.40	3.15E-07	9.94E-01	3.13E-07
1.5	>1.5	1.65	3.63E-07	9.98E-01	3.62E-07
Total Seismic LOOP Frequency =					2.7E-05

6. Conclusions

Based on this analysis of external hazards for LGS Units 1 and 2, no additional external hazards other than seismic events need to be added to the existing PRA model. The evaluation concluded that the hazards either do not present a design-basis challenge to LGS, the challenge is adequately addressed in the PRA, or the hazard has a negligible impact on the calculated RICT and can be excluded.

The ICDP/ILERP acceptance criteria of 1E-5/1E-6 will be used within the PARAGON framework to calculate the resulting RICT and RMAT based on the total configuration-specific delta CDF/LERF attributed to internal events and internal fire, plus the seismic bounding delta CDF/LERF values.

Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models

7. References

1. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, dated October 12, 2012 (ADAMS Accession No. ML12286A322).

2. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," dated May 17, 2007 (ADAMS Accession No. ML071200238).

3. ASME/ANS RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," Addendum A to RAS-2008, ASME, New York, NY, American Nuclear Society, La Grange Park, Illinois, February 2009.

4. NUREG-1855, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making," Revision 1, March 2017.

5. NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition," 1975.

6. NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991.

7. Philadelphia Electric Company, Individual Plant Examination External Events (IPEEE), Limerick Generating Station, Units 1 and 2, June 26, 1995.

8. Lettis Consultants International (LCI), Inc., Project No. 1041, "Limerick Seismic Hazard and Screening Report," November 25, 2013.

9. Exelon Generation Company, LLC, RS-14-069, "Seismic Hazard and Screening Report (Central and Eastern United States (CEUS) Sites), Response to NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding Recommendation 2.1 of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident ", March 31, 2015.

10. Review of Individual Plant Examination of External Events (IPEEE) Submittal, Limerick Generating Station, Units 1 and 2 (TAC NOS. M83636 and M83637), US Nuclear Regulatory Commission, February 28, 2000. [This includes a safety evaluation report (SER)].

11. Generic Issue 199, "Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants," U.S. NRC IN 2010-18, September 2, 2010.

12. Staff Report, "Implications of Updated Probabilistic Seismic Hazard Estimates In Central And Eastern United States On Existing Plants, Safety/Risk Assessment," ML100270639, August 2010.

13. LG-LAR-011, Revision 1, Bounding Seismic CDF and LERF Estimate for TSTF-505 (RICT) Program, October 2018.

14. LG-PRA-013, Revision 4, “Limerick Generating Station, Probabilistic Risk Assessment, 2013 PRA Update, Summary Notebook, LG117A and LG217A [at power, internal events] Models,” July 2018.

15. LGS UFSAR, Revision 18, September 2018.

16. NUREG/CR-4461, “Tornado Climatology of the Contiguous United States,” Revision 2, February 2007.

17. NUS-4507, “Limerick Generating Station – Ultimate Heat Sink Extreme Winds Hazard Analysis,” March 1984.

18. NUREG-0991, “Safety Evaluation Report related to the operation of Limerick Generating Station, Units 1 and 2," May 1985.

19. LG-LAR-014, "LGS High Winds Evaluation for 4b Submittal."

20. “Risk Assessment of Operational Events, Volume 2 – External Events – Internal Fires – Internal Flooding – Seismic – Other External Events – Frequencies of Seismically-Induced LOOP Events" (Risk Assessment Standardization Project [RASP] Handbook), Revision 1.02, US Nuclear Regulatory Commission, November 2017.

21. Limerick Generating Station – Units 1 & 2 Flood Hazard Reevaluation Report (FHRR), NRC ADAMS Accession No. ML15084A586, March 12, 2015.

22. Regulatory Guide 1.78, “Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release,” Revision 1, December 2001.

23. Regulatory Guide 1.91, "Evaluations and Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants," Revision 2, April 2013.

24. NEI16-09, Risk-Informed Engineering Programs (10 CFR 50.69) Implementation Guidance, Revision 0.

25. IR 870181 A04, “Review of Limerick Offsite Hazardous Chemical Survey,” Revision 0, 2008.

26. NUREG/CR-2300, “PRA Procedures Guide: A Guide to the Performance of Probabilistic Risk Assessments for Nuclear Power Plants,” January 1983.

ENCLOSURE 5

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)

Baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)

1. Introduction

Section 4.0, Item 6 of the Nuclear Regulatory Commission's (NRC) Final Safety Evaluation (Reference 1) for NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0 (Reference 2) requires that the license amendment request (LAR) provide the plant-specific total CDF and LERF to confirm applicability of the limits of Regulatory Guide (RG) 1.174, Revision 1 (Reference 3). (Note that RG 1.174, Revision 2 (Reference 4), issued by the NRC in May 2011, did not revise these limits.)

The purpose of this enclosure is to demonstrate that the Limerick Generating Station (LGS) total Core Damage Frequency (CDF) and total Large Early Release Frequency (LERF) are below the guidelines established in RG 1.174. RG 1.174 does not establish firm limits for total CDF and LERF but recommends that risk-informed applications be implemented only when the total plant risk is no more than about 1E-4/year for CDF and 1E-5/year for LERF. Demonstrating that these limits are met confirms that the risk metrics of NEI 06-09-A can be applied to the LGS Risk Informed Completion Time (RICT) Program.

2. Technical Approach

Table E5-1 lists the LGS Unit 1 and Unit 2 CDF and LERF values that resulted from a quantification of the baseline internal events (including internal flooding) and fire Probabilistic Risk Assessment (PRA) models (References 5 and 6, respectively). This table also includes an estimate of the seismic contribution to CDF and LERF based on the methodology detailed in Enclosure 4. Other external hazards are below accepted screening criteria and therefore do not contribute significantly to the totals.

Table E5-1
Total Baseline CDF/LERF

Unit 1 Baseline CDF			**Unit 1 Baseline LERF**	
Source	**Contribution**		**Source**	**Contribution**
Internal Events PRA	3.2E-06		Internal Events PRA	2.1E-07
Fire PRA	5.2E-06		Fire PRA	8.7E-08
Seismic	3.7E-06		Seismic	7.4E-07
Other External Events	No significant contribution		Other External Events	No significant contribution
Total Unit 1 CDF	**1.2E-05**		**Total Unit 1 LERF**	**1.0E-06**

Baseline Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)

Table E5-1
Total Baseline CDF/LERF

Unit 2 Baseline CDF			**Unit 2 Baseline LERF**	
Source	**Contribution**		**Source**	**Contribution**
Internal Events PRA	3.2E-06		Internal Events PRA	2.1E-07
Fire PRA	5.2E-06		Fire PRA	9.5E-08
Seismic	3.7E-06		Seismic	7.4E-07
Other External Events	No significant contribution		Other External Events	No significant contribution
Total Unit 2 CDF	**1.2E-05**		**Total Unit 2 LERF**	**1.0E-06**

As demonstrated in Table E5-1, the total CDF and total LERF are within the guidelines set forth in RG 1.174 and support small changes in risk that may occur during RICT entries following TSTF-505 implementation. Therefore, LGS TSTF-505 implementation is consistent with NEI 06-09-A guidance.

3. References

1. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,'" dated May 17, 2007 (ADAMS Accession No. ML071200238).

2. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, dated October 12, 2012 (ADAMS Accession No. ML12286A322).

3. Regulatory Guide 1.174, "An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1, November 2002.

4. Regulatory Guide 1.174, "An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 2, May 2011 (Accession No. ML10091006).

5. LG-PRA-013, Summary Notebook, LG117A and LG217A Models, July 2018.

6. LG-PRA-021.11, LGS FPRA Summary & Quantification Notebook, November 2018.

ENCLOSURE 6

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Justification of Application of At-Power PRA Models to Shutdown Modes

This enclosure is not applicable to the Limerick Generating Station submittal. Exelon is proposing to apply the Risk-Informed Completion Time Program only in Modes 1 and 2 and not in the shutdown Modes.

ENCLOSURE 7

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

PRA Model Update Process

PRA Model Update Process

1. Introduction

Section 4.0, Item 8 of the Nuclear Regulatory Commission's (NRC) Final Safety Evaluation (Reference 1) for NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0 (Reference 2) requires that the license amendment request (LAR) provide a discussion of the licensee's programs and procedures which assure the PRA models which support the RMTS are maintained consistent with the as-built/as-operated plant.

This enclosure describes the administrative controls and procedural processes applicable to the configuration control of PRA models used to support the Risk-Informed Completion Time (RICT) Program, which will be in place to ensure that these models reflect the as-built/as-operated plant. Plant changes, including physical modifications and procedure revisions, will be identified and reviewed prior to implementation to determine if they could impact the PRA models per ER-AA-600-1015, FPIE [Full Power Internal Events] PRA Model Update (Reference 3), and ER-AA-600-1061, Fire PRA Model Update and Control (Reference 4). The configuration control program will ensure these plant changes are incorporated into the PRA models as appropriate. The process will include discovered conditions associated with the PRA models, which will be addressed by the applicable site Corrective Action Program.

Should a plant change or a discovered condition be identified that has a significant impact to the RICT Program calculations as defined by the above procedures, an unscheduled update of the PRA model will be implemented. Otherwise, the PRA model change is incorporated into a subsequent periodic model update. Such pending changes are considered when evaluating other changes until they are fully implemented into the PRA models. Periodic updates are typically performed every four years.

2. PRA Model Update Process

Internal Event, Internal Flood, and Fire PRA Model Maintenance and Update

The Exelon fleet risk management process ensures that the applicable PRA model used for the RICT Program reflects the as-built/as-operated plant for each of the Limerick units. The PRA configuration control process delineates the responsibilities and guidelines for updating the full power internal events, internal flood, and fire PRA models, and includes both periodic and unscheduled PRA model updates.

The process includes provisions for monitoring potential impact areas affecting the technical elements of the PRA models (e.g., due to plant changes, plant/industry operational experience, or errors or limitations identified in the model), assessing the individual and cumulative risk impact of unincorporated changes, and controlling the model and necessary computer files, including those associated with the Real-Time Risk model.

Changes to the PRA models that are considered an upgrade per the ASME/ANS PRA Standard receive a peer review focused on those aspects of the PRA models that represent the upgrade.

PRA Model Update Process

Review of Plant Changes for Incorporation into the PRA Model

1. Plant changes or discovered conditions are reviewed for potential impact to the PRA models, including the Real-Time Risk model and the subsequent risk calculations which support the RICT Program (NEI 06-09-A, Section 2.3.4, Items 7.2 and 7.3, and 2.3.5, Items 9.2 and 9.3).

2. Plant changes that meet the criteria defined in References 3 and 4 (including consideration of the cumulative impact of other pending changes) will be incorporated into the applicable PRA model(s), consistent with the NEI 06-09-A guidance. Otherwise, the change is assigned a priority and is incorporated at a subsequent periodic update consistent with procedural requirements. (NEI 06-09-A, Section 2.3.5, Item 9.2)

3. PRA updates for plant changes are performed at least once every two refueling cycles, consistent with the guidance of NEI 06-09-A (NEI 06-09-A, Section 2.3.4, Item 7.1, and 2.3.5, Item 9.1).

4. If a PRA model change is required for the Real-Time Risk model, but cannot be immediately implemented for a significant plant change or discovered condition, either:

   a. Interim analyses to address the expected risk impact of the change will be performed. In such a case, these interim analyses become part of the RICT Program calculation process until the plant changes are incorporated into the PRA model during the next update. The use of such bounding analyses is consistent with the guidance of NEI 06-09-A.

      OR

   b. Appropriate administrative restrictions on the use of the RICT Program for extended Completion Times are put in place until the model changes are completed, consistent with the guidance of NEI 06-09-A.

   These actions satisfy NEI 06-09-A, Section 2.3.5, Item 9.3.

3. References

1. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,'" dated May 17, 2007 (ADAMS Accession No. ML071200238).

2. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, dated October 12, 2012 (ADAMS Accession No. ML12286A322).

3. ER-AA-600-1015, "FPIE PRA Model Update."

4. ER-AA-600-1061, "Fire PRA Model Update and Control."

ENCLOSURE 8

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

<u>Attributes of the Real-Time Risk Model</u>

Attributes of the Real-Time Risk Model

1. Introduction

Section 4.0, Item 9 of the Nuclear Regulatory Commission's (NRC) Final Safety Evaluation (Reference 1) for NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0 (Reference 2) requires that the license amendment request (LAR) provide a description of PRA models and tools used to support the RMTS. This includes identification of how the baseline probabilistic risk assessment (PRA) model is modified for use in the Real-Time Risk (RTR) tools, quality requirements applied to the PRA models and RTR tools, consistency of calculated results from the PRA model and the RTR tools, and training and qualification programs applicable to personnel responsible for development and use of the RTR tools. This item should also confirm that the RICT program tools can be readily applied for each Technical Specification (TS) limiting condition for operation (LCO) within the scope of the plant-specific submittal.

This enclosure describes the necessary changes to the peer-reviewed baseline PRA models for use in the RTR software to support the Risk-Informed Completion Time (RICT) Program. The process employed to adapt the baseline models is demonstrated:

a) to preserve the core damage frequency (CDF) and large early release frequency (LERF) quantitative results;
b) to maintain the quality of the peer-reviewed PRA models; and
c) to correctly accommodate changes in risk due to configuration-specific considerations.

Quality controls and training programs applicable for the RICT Program are also discussed in this enclosure.

2. Translation of Baseline PRA Model for Use in Real-Time Risk

The baseline PRA models for internal events, including internal flood and internal fire, are the peer-reviewed models. These models are updated when necessary to incorporate plant changes to reflect the as-built/as-operated plant. The internal flood model is integrated into the internal events model. The Fire PRA model is maintained as a separate model. These models will be used in the RTR Program. The models may be optimized for quantification speed but are verified to provide the same result as the baseline models in accordance with approved procedures.

The RTR risk software will be used to facilitate all configuration-specific risk calculations and support the RICT Program implementation. The baseline PRA models are modified as follows for use in configuration risk calculations:

- The unit availability factor is set to 1.0 (unit available).
- Maintenance unavailability is set to zero/false unless unavailable due to the configuration.
- Mutually exclusive combinations, including normally disallowed maintenance combinations, are adjusted to allow accurate analysis of the configuration.

Attributes of the Real-Time Risk Model

- For systems where some trains are in service and some in standby, the RTR model addresses the actual configuration of the plant including defining in-service trains as needed.

The RTR software is designed to quantify the unit-specific configuration for both internal events, including internal flooding and fire, and includes the seismic risk contribution when calculating the RMAT and RICT. The unique aspect of the RTR software for the RICT program is the quantification of fire risk and the inclusion of the seismic risk contribution. The other adjustments above are those used for the evaluation of risk under the 10CFR 50.65(a)(4) program.

3. Quality Requirements and Consistency of PRA Model and Real-Time Risk Tools

The approach for establishing and maintaining the quality of the PRA models, including the RTR model, includes both a PRA model update process (described in Enclosure 7) and the use of self-assessments and independent peer reviews (described in Enclosure 2).

The information provided in Enclosure 2 demonstrates that the site's internal event, internal flood, and internal fire PRA models reasonably conform to the associated industry standards endorsed by Regulatory Guide 1.200 (Reference 3). This information provides a robust basis for concluding that the PRA models are of sufficient quality for use in risk-informed licensing actions.

For maintenance of an existing RTR model, changes made to the baseline PRA model in translation to the RTR model will be controlled and documented. An acceptance test is performed after every RTR model update. This testing also verifies correct mapping of plant components to the basic events in the RTR model.

4. Training and Qualification

The PRA staff is responsible for development and maintenance of the RTR model. Operations and Work Control staff will use the RTR tool under the RICT Program. PRA Staff and Operations are trained in accordance with a program using National Academy for Nuclear Training (ACAD) documents, which is also accredited by INPO.

5. Application of the Real-Time Risk Tool to the RICT Program Scope

The PARAGON software is the RTR tool and will be used to facilitate all configuration-specific risk calculations and support the RICT Program implementation. This program is specifically designed to support implementation of RMTS. PARAGON will permit the user to evaluate all plant configurations using appropriate mapping of equipment to PRA basic events. The equipment in the scope of the RICT program will be able to be evaluated in the appropriate PRA models. The RTR will meet RG 1.174 (Reference 4) and Exelon software quality assurance requirements.

Attributes of the Real-Time Risk Model

6. References

1. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,'" dated May 17, 2007 (ADAMS Accession No. ML071200238).

2. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, dated October 12, 2012 (ADAMS Accession No. ML12286A322).

3. Regulatory Guide 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 2, March 2009.

4. Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 2, May 2011.

ENCLOSURE 9

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Key Assumptions and Sources of Uncertainty

Key Assumptions and Sources of Uncertainty

1. Introduction

The purpose of this enclosure is to disposition the impact of Probabilistic Risk Assessment (PRA) modeling epistemic uncertainty for the Risk Informed Completion Time (RICT) Program. Topical Report NEI 06-09-A (Reference 1), Section 2.3.4, item 10 requires an evaluation to determine insights that will be used to develop risk management actions (RMAs) to address these uncertainties. The baseline internal events PRA and fire PRA (FPRA) models document assumptions and sources of uncertainty and these were reviewed during the model peer reviews. The approach taken is, therefore, to review these documents to identify the items which may be directly relevant to the RICT Program calculations, to perform sensitivity analyses where appropriate, to discuss the results and to provide dispositions for the RICT Program.

The epistemic uncertainty analysis approach described below applies to the internal events PRA and any epistemic uncertainty impacts that are unique to FPRA are also addressed. In addition, Topical Report NEI 06-09-A requires that the uncertainty be addressed in RICT Program Configuration Risk Management Program (CRMP), otherwise referred to as the Real-Time Risk (RTR), tools by consideration of the translation from the PRA model to the RTR model. The RTR model, also referred to as the PARAGON model, discussed in Enclosure 8 includes internal events, flooding events and fire events. The model translation uncertainties evaluation and impact assessment are limited to new uncertainties that could be introduced by application of the RTR tool during RICT Program calculations.

2. Assessment of Internal Events PRA Epistemic Uncertainty Impacts

In order to identify key sources of uncertainty for RICT Program application, an evaluation of internal events baseline PRA model uncertainty was performed, based on the guidance in NUREG-1855 (Reference 2) and Electric Power Research Institute (EPRI) report TR-1016737 (Reference 3). As described in NUREG-1855, sources of uncertainty include “parametric” uncertainties, “modeling” uncertainties, and “completeness” (or scope and level of detail) uncertainties.

Parametric uncertainty was addressed as part of the Limerick Generating Station (LGS) baseline PRA model quantification (Reference 4).

Modeling uncertainties are considered in both the base PRA and in specific risk-informed applications. Assumptions are made during the PRA development as a way to address a particular modeling uncertainty because there is not a single definitive approach. Plant-specific assumptions made for each of the LGS internal events PRA technical elements are noted in the individual notebooks. These assumptions were collected from each notebook. The internal events PRA model uncertainties evaluation is documented in Reference 5 and considers the modeling uncertainties for the base PRA by identifying assumptions, determining if those assumptions are related to a source of modeling uncertainty and characterizing that uncertainty, as necessary. EPRI compiled a listing of generic sources of modeling uncertainty to be considered for each PRA technical element (Reference 3), and the evaluation performed for LGS (Reference 5) considered each of the generic sources of modeling uncertainty as well as the plant-specific sources.

Key Assumptions and Sources of Uncertainty

Completeness uncertainty addresses scope and level of detail. Uncertainties associated with scope and level of detail are documented in the PRA but are only considered for their impact on a specific application (Reference 4). No specific issues of PRA completeness have been identified relative to the TSTF-505 application, based on the results of the internal events PRA and fire PRA peer reviews.

Based on following the methodology in EPRI TR-1016737 for a review of sources of uncertainty, the impact of potential sources of uncertainty on the RICT application is discussed in Table E9-1, which identifies those potential sources that may be key sources of uncertainty for the RICT program. Note that RMAs will be developed when appropriate using insights from the PRA model results specific to the configuration. This will include a review for impacts due to the key sources of uncertainty.

Table E9-1
Assessment of Internal Events PRA Epistemic Uncertainty Impacts

Source of Uncertainty and Assumptions	TS LCOs	Model Sensitivity and Disposition
Continued injection from control rod drive (CRD) after containment failure is credited unless a gross rupture of containment (i.e., not leak before break) occurs. The probability of rupture is based on a detailed structural analysis of the Mark II design.	LCOs for which loss of containment heat removal scenarios have an effect on the RICT	This approach provides a best estimate assessment for the site. However, the TSTF-505 procedure will require appropriate risk management action (RMA) focus on human performance for RICT entry, e.g., including an operator briefing on the significant human actions in the PRA that are pertinent to the configuration (in this case loss of containment heat removal scenarios). Refer to Enclosure 12 for additional discussion on RMAs.
The base PRA model includes an assumption that 2 emergency diesel generator (EDG) HVAC fans are required 25% of the time, and only 1 EDG HVAC fan is required for the remaining 75% of the time.	LCOs for which the availability of on-site ac power have an effect on the RICT	The RTR will include explicit representation of the number of DG HVAC required to provide DG cooling whenever a DG HVAC is removed from service. Therefore, this does not represent a key source of uncertainty and will not be an issue for RICT calculations.

Key Assumptions and Sources of Uncertainty

Table E9-1
Assessment of Internal Events PRA Epistemic Uncertainty Impacts

Source of Uncertainty and Assumptions	TS LCOs	Model Sensitivity and Disposition
The postulated reactor pressure vessel (RPV) overpressure failure mode is assumed to be equivalent to the Large LOCA success criteria.	LCOs for which Low Pressure Injection (LPI) systems are involved in the RICT	An alternative assumption would be that such scenarios are beyond the capabilities of the LPI systems. Therefore, crediting LPI capabilities for these scenarios may provide a slight non-conservative bias on the RICT calculations. However, because RPV overpressure scenarios are very low frequency events, this does not represent a key source of uncertainty and will not be an issue for RICT calculations.
Low pressure emergency core cooling system (ECCS) restoration after core damage but prior to vessel failure is assumed to lead to a condition where large early release is avoided.	LCOs for which the LERF results may have some effect on the RICT	This assumption precludes some of the low likelihood phenomenological contributors to LERF from contributing to the overall results. However, it is judged reasonable, based on sensitivity analyses performed with the MAAP4 computer code for a similar BWR plant, that the availability of low pressure injection at the time of vessel failure (should it occur) will also greatly reduce the potential for a large early release from occurring. Therefore, this assumption provides a reasonable best-estimate approach, will have only a minor impact on the RICT calculations, and does not represent a key source of uncertainty for the RICT application.

Key Assumptions and Sources of Uncertainty

Table E9-1 Assessment of Internal Events PRA Epistemic Uncertainty Impacts		
Source of Uncertainty and Assumptions	TS LCOs	Model Sensitivity and Disposition
If containment failure occurs prior to core damage in Anticipated Transient Without Scram (ATWS) scenarios that could result in LERF, only injection from residual heat removal service water (RHRSW) is credited to provide core melt arrest in-vessel. Besides the failure modes of implementing RHRSW injection, additional failure modes are included for harsh reactor building environment or piping failures due to containment failure.	LCOs for which ATWS LERF scenarios may have some effect on the RICT	The values utilized provide a reasonable best-estimate approach and will have only a minor impact on the RICT calculations and does not represent a key source of uncertainty for the RICT application.
Ex-vessel core melt progression overwhelming vapor suppression is considered in the LERF model with different values for low pressure RPV failure sequences and high pressure RPV failure sequences based on available information.	LCOs for which the LERF results may have some effect on the RICT	The values utilized provide a reasonable best-estimate approach, will have only a minor impact on the RICT calculations, and do not represent a key source of uncertainty for the RICT application.
Given the set of conditions occur(e.g., if level is not maintained below Level 8, the automatic trip functions fail, and operators do not respond in time to take manual control of HPCI or RCIC after the Level 8 trip failure) that would allow uncontrolled flooding of the steam lines, a probability is assigned that this uncontrolled flooding permanently disables all of the SRVs precluding the ability to depressurize the RPV through the SRVs.	LCOs which involve High Pressure Injection Systems	Although the SRVs at LGS are designed to pass water, and licensing basis fire safe shutdown methods include the RPV being flooded with water returned to the Suppression Pool via the SRVs they are never tested in this fashion. A nominal 1E-03 failure probability is assigned to provide a slight conservative bias slant to the results such that the impact on RICT calculations is not unduly influenced. This does not represent a key source of uncertainty for the RICT application

Key Assumptions and Sources of Uncertainty

Table E9-1
Assessment of Internal Events PRA Epistemic Uncertainty Impacts

Source of Uncertainty and Assumptions	TS LCOs	Model Sensitivity and Disposition
Containment integrity following a vessel rupture event (i.e., excessive LOCA) is not assured. There is model uncertainty regarding the subsequent treatment that increases the likelihood of LERF for this extremely rare event.	N/A	The current model treatment results in addition of a constant value to the CDF and LERF results. There is no impact for any RICT calculations. Therefore, this does not represent a key source of uncertainty for the RICT application.
Digital feedwater control failure probabilities are derived from the reliability values in the vendor study (Reference 6) demonstrating that the system performance would result in less than 0.1 transients per year and these reliability values are used for the key components of the system.	LCOs which involve High Pressure Injection Systems	The values utilized provide a reasonable best-estimate approach and will have only a minor impact on the RICT calculations. This does not represent a key source of uncertainty for the RICT application.

Key Assumptions and Sources of Uncertainty

Table E9-1 Assessment of Internal Events PRA Epistemic Uncertainty Impacts		
Source of Uncertainty and Assumptions	TS LCOs	Model Sensitivity and Disposition
Uncertainties associated with the assumptions and method of calculation of Human Error Probabilities (HEPs) for the Human Reliability Analysis (HRA) may introduce uncertainty. Detailed evaluations of HEPs are performed for the risk significant human failure events (HFEs) using industry consensus methods. Mean values are used for the modeled HEPs. Uncertainty associated with the mean values can have an impact on CDF and LERF results.	Potentially all LCOs in the RICT program	Sensitivity cases performed using the base internal events PRA (HEP values of 0.0 or use of the 95th percentile value HEPs) indicate some sensitivity to human performance. Use of 95th percentile HEPs for applications is not considered realistic given the consistent use of a consensus HRA approach. The LGS PRA model is based on industry consensus modeling approaches for its HEP calculations, so this is not considered a significant source of epistemic uncertainty. However, the TSTF-505 process requires appropriate risk management action (RMA) development, including those related to operator actions in the PRA that are pertinent to the RICT configuration. Refer to Enclosure 12 for additional discussion on RMAs.

Key Assumptions and Sources of Uncertainty

Table E9-1 Assessment of Internal Events PRA Epistemic Uncertainty Impacts		
Source of Uncertainty and Assumptions	TS LCOs	Model Sensitivity and Disposition
Dependent HEP values are developed for significant combinations of HEPs that have been demonstrated to appear together in the same cutsets.	Potentially all LCOs in the RICT program	The LGS PRA model is based on industry consensus modeling approaches for its dependent HEP identification and calculations, so this is not considered a significant source of epistemic uncertainty. However, the TSTF-505 procedure will require appropriate risk management action (RMA) focus on human performance for RICT entry, e.g., including an operator briefing on the significant human actions in the PRA that are pertinent to the configuration. Refer to Enclosure 12 for additional discussion on RMAs.
Common cause failure values are developed using available industry data.	Potentially all LCOs in the RICT program	The LGS PRA model is based on industry consensus modeling approaches for its common cause identification and value determination, so this is not considered a significant source of epistemic uncertainty. For unplanned entries into a RICT, the TSTF-505 process requires consideration of the potential for common cause failure and identification of RMAs to mitigate this potential if the extent of condition is not known. Therefore, this does not represent a key source of uncertainty and will not be an issue for RICT calculations.

Key Assumptions and Sources of Uncertainty

Table E9-1 Assessment of Internal Events PRA Epistemic Uncertainty Impacts		
Source of Uncertainty and Assumptions	TS LCOs	Model Sensitivity and Disposition
There are model uncertainties associated with modeling the probability of the RHR pumps failing from a rupture due to a water hammer event given the RHR system is operating in suppression pool cooling mode at the time of the initiating event and the appropriate operator responses do not occur such that a potential water hammer event can occur.	LCOs which involve the RHR or RHRSW Systems	The water hammer basic events and values utilized provide a reasonable best-estimate approach and will have only a minor impact on the RICT calculations. This does not represent a key source of uncertainty for the RICT program. The TSTF-505 procedure will require appropriate risk management action (RMA) focus on human performance for RICT entry, e.g., including an operator briefing on the significant human actions in the PRA that are pertinent to the configuration such as venting the RHR line before restart of the RHR pump. Refer to Enclosure 12 for additional discussion on RMAs.

3. Assessment of Translation (RTR Model) Uncertainty Impacts

Incorporation of the baseline PRA models into the RTR model used for RICT Program calculations may introduce new sources of model uncertainty. Table E9-2 provides a description of the relevant model changes and dispositions of whether any of the changes made represent possible new sources of model uncertainty that must be addressed. Refer to Enclosure 8 for additional discussion on the RTR model.

Key Assumptions and Sources of Uncertainty

Table E9-2
Assessment of Translation Uncertainty Impacts

RTR Model Change and Assumptions	Part of Model Affected	Impact on Model	Disposition
PRA model logic structure may be optimized to increase solution speed.	Fault tree logic model structure, affecting both internal and fire PRAs	The model, if restructured, will be logically equivalent and produce results comparable to the baseline PRA logic model	Since the restructured model will produce comparable numerical results, this is not a source of uncertainty for the RICT program.
Incorporation of seismic risk bias to support RICT Program risk calculations. A conservative value for the seismic delta CDF is applicable.	Calculation of RICT and RMAT within RTR model	The addition of bounding impacts for seismic events has no impact on baseline PRA or RTR model. Impact is reflected in calculation of all RICTs and RMATs.	Since this is a bounding approach for addressing seismic risk in the RICT Program, it is not a source of translation uncertainty, and RICT Program calculations are not impacted, so no mandatory RMAs are required.
Set plant availability (Reactor Critical Years Factor) basic event to 1.0.	Basic event ZZAVFACTOR	Since the RTR model evaluates specific configurations during at-power conditions, the use of a plant availability factor less than 1.0 is not appropriate. This change allows the RTR model to produce appropriate results for specific at-power configurations.	This change is consistent with RTR tool practice; therefore, this change does not represent a source of uncertainty, and RICT program calculations are not impacted, so no mandatory RMAs are required.

Key Assumptions and Sources of Uncertainty

4. Assessment of Supplementary FPRA Epistemic Uncertainty Impacts

The purpose of the following discussion is to address the epistemic uncertainty in the LGS FPRA. The LGS FPRA model includes various sources of uncertainty that exist because there is both inherent randomness in elements that comprise the FPRA and because the state of knowledge in these elements continues to evolve. The development of the LGS FPRA was guided by NUREG/CR-6850 (Reference 7). The LGS FPRA model used consensus models described in NUREG/CR-6850.

LGS used guidance provided in NUREG/CR-6850 and NUREG-1855 to address uncertainties associated with FPRA for the RICT Program application. As stated in Section 1.3 of NUREG-1855:

> "Although the guidance in this report does not currently address all sources of uncertainty, the guidance provided on the uncertainty identification and characterization process and on the process of factoring the results into the decision making is generic and independent of the specific source of uncertainty. Consequently, the guidance is applicable for sources of uncertainty in PRAs that address at-power and low power and shutdown operating conditions, and both internal and external hazards."

NUREG-1855 also describes an approach for addressing sources of model uncertainty and related assumptions. It defines:

> "A source of model uncertainty exists when (1) a credible assumption (decision or judgment) is made regarding the choice of the data, approach, or model used to address an issue because there is no consensus and (2) the choice of alternative data, approaches or models is known to have an impact on the PRA model and results. An impact on the PRA model could include the introduction of a new basic event, changes to basic event probabilities, change in success criteria, or introduction of a new initiating event. A credible assumption is one submitted by relevant experts and which has a sound technical basis. Relevant experts include those individuals with explicit knowledge and experience for the given issue. An example of an assumption related to a source of model uncertainty is battery depletion time. In calculating the depletion time, the analyst may not have any data on the time required to shed loads and thus may assume (based on analyses) that the operator is able to shed certain electrical loads in a specified time."

Key Assumptions and Sources of Uncertainty

NUREG-1855 defines consensus model as:

> “A model that has a publicly available published basis and has been peer reviewed and widely adopted by an appropriate stakeholder group. In addition, widely accepted PRA practices may be regarded as consensus models. Examples of the latter include the use of the constant probability of failure on demand model for standby components and the Poisson model for initiating events. For risk-informed regulatory decisions, the consensus model approach is one that NRC has utilized or accepted for the specific risk-informed application for which it is proposed.”

The potential sources of model uncertainty in the LGS FPRA model were characterized for the 16 tasks identified by NUREG/CR-6850 in Table E9-3. This framework was used to organize the assessment of baseline FPRA epistemic uncertainty and evaluate the impact of this uncertainty on RICT Program calculations. Table E9-3 outlines sources of uncertainties by task and their disposition.

As noted above, the LGS FPRA was developed using consensus methods outlined in NUREG/CR-6850 and interpretations of technical approaches as required by NRC. Further, appropriate cable impacts were identified for the systems modeled in the Internal Events PRA and were modeled in the Fire PRA. No systems were conservatively assumed to be failed for all FPRA scenarios. Fire PRA methods were based on NUREG/CR-6850, other more recent NUREGs, e.g., NUREG-7150 (Reference 8), and published “frequently asked questions” (FAQs) for the FPRA.

Key Assumptions and Sources of Uncertainty

Table E9-3: Fire PRA Sources of Model Uncertainty			
Task #	Description	Sources of Uncertainty	Disposition for RICT Application
1	Analysis boundary and partitioning	This task establishes the overall spatial scope of the analysis and provides a framework for organizing the data for the analysis. The partitioning features credited are required to satisfy established industry standards.	Based on the discussion of sources of uncertainly it is concluded that the methodology for the Analysis Boundary and Partitioning task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
2	Component Selection	This task involves the selection of components to be treated in the analysis in the context of initiating events and mitigation. The potential sources of uncertainty include those inherent in the internal events PRA model as that model provides the foundation for the FPRA.	In the context of the FPRA, the uncertainty that is unique to the analysis is related to initiating event identification. However, that impact is minimized through use of the BWROG Generic Multiple Spurious Operation (MSO) list and the process used to identify and assess potential MSOs. Based on the discussion of sources of uncertainty and the discussion above, it is concluded that the methodology for the Component Selection task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

Key Assumptions and Sources of Uncertainty

Table E9-3: Fire PRA Sources of Model Uncertainty			
Task #	Description	Sources of Uncertainty	Disposition for RICT Application
3	Cable Selection	The selection of cables to be considered in the analysis is identified using industry guidance documents. The overall process is essentially the same as that used to perform the analyses to demonstrate compliance with 10 CFR 50.48.	Based on the discussion of sources of uncertainty it is concluded that the methodology for the Cable Selection task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
4	Qualitative Screening	Qualitative screening was performed; however, some structures (locations) were eliminated from the global analysis boundary and ignition sources deemed to have no impact on the FPRA (based on industry guidance and criteria) were excluded from the quantification based on qualitative screening criteria. The only criterion subject to uncertainty is the potential for plant trip. However, such locations would not contain any features (equipment or cables identified in the prior two tasks) and consequently are expected to have a low risk contribution.	In the event a structure (location) which could result in a plant trip was incorrectly excluded, its contribution to CDF would be small (with a CCDP commensurate with base risk). Such a location would have a negligible risk contribution to the overall FPRA. Based on the discussion of sources of uncertainty and the discussion above, it is concluded that the methodology for the Qualitative Screening task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

Key Assumptions and Sources of Uncertainty

Table E9-3: Fire PRA Sources of Model Uncertainty			
Task #	Description	Sources of Uncertainty	Disposition for RICT Application
5	Fire-Induced Risk Model	The internal events PRA model was updated to add fire specific initiating event structure as well as additional system logic. The methodology used is consistent with that used for the internal events PRA model development and was subjected to industry Peer Review. The developed model is applied in such a fashion that all postulated fires are assumed to generate a plant trip. This represents a source of uncertainty, as it is not necessarily clear that fires would result in a trip. In the event the fire results in damage to cables and/or equipment identified in Task 2, the PRA model includes structure to translate them into the appropriate induced initiator.	The identified source of uncertainty could result in the over-estimation of fire risk. In general, the FPRA development process would have reviewed significant fire initiating events and performed supplemental assessments to address this possible source of uncertainty. Based on the discussion of sources of uncertainty and the discussion above, it is concluded that the methodology for the Fire-Induced Risk Model task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

Key Assumptions and Sources of Uncertainty

Table E9-3: Fire PRA Sources of Model Uncertainty

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
6	Fire Ignition Frequency	Fire ignition frequency is an area with inherent uncertainty. Part of this uncertainty arises due to the counting and related partitioning methodology. However, the resulting frequency is not particularly sensitive to changes in ignition source counts. The primary source of uncertainty for this task is associated with the industry generic frequency values used for the FPRA. This is because there is no specific treatment for variability among plants along with some significant conservatism in defining the frequencies, and their associated heat release rates. LGS uses the ignition frequencies in NUREG-2169 (Reference 9) along with the revised heat release rates from NUREG 2178 (Reference 10).	Based on the discussion of sources of uncertainty, it is concluded that the methodology for the Fire Ignition Frequency task does not introduce any epistemic uncertainties that would affect the RICT calculation. Consensus approaches are employed in the model. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
7	Quantitative Screening	Other than screening out potentially risk significant scenarios (ignition sources), this task is not a source of uncertainty.	The LGS FPRA did not screen out any fire scenarios based on low CDF/LERF contribution. That is, quantified fire scenarios results are retained in the cumulative CDF/LERF. Based on the discussion of sources of uncertainty and the discussion above, it is concluded that the methodology for the Quantitative Screening task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

Key Assumptions and Sources of Uncertainty

Table E9-3: Fire PRA Sources of Model Uncertainty			
Task #	Description	Sources of Uncertainty	Disposition for RICT Application
8	Scoping Fire Modeling	The framework of NUREG/CR-6850 includes two tasks related to fire scenario development. These two tasks are 8 and 11. The discussion of uncertainty for both tasks is provided in the discussion for Task 11.	See Task 11 discussion.
9	Detailed Circuit Failure Analysis	The circuit analysis is performed using standard electrical engineering principles. However, the behavior of electrical insulation properties and the response of electrical circuits to fire induced failures is a potential source of uncertainty. This uncertainty is associated with the dynamics of fire and the inability to ascertain the relative timing of circuit failures. The analysis methodology assumes failures would occur in the worst possible configuration, or if multiple circuits are involved, at whatever relative timing is required to cause a bounding worst-case outcome. This results in a skewing of the risk estimates such that they are over-estimated.	Circuit analysis was performed as part of the deterministic post fire safe shutdown analysis. Refinements in the application of the circuit analysis results to the FPRA were performed on a case-by-case basis where the scenario risk quantification was large enough to warrant further detailed analysis. Hot short probabilities and hot short duration probabilities as defined in NUREG-7150, Volume 2 (Reference 8), based on actual fire test data, were used in the LGS Fire PRA. The uncertainty (conservatism) which may remain in the FPRA is associated with scenarios that do not contribute significantly to the overall fire risk. Based on the discussion of sources of uncertainty and the discussion above, it is concluded that the methodology for the Detailed Circuit Failure Analysis task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

Key Assumptions and Sources of Uncertainty

Table E9-3: Fire PRA Sources of Model Uncertainty

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
10	Circuit Failure Mode Likelihood Analysis	One of the failure modes for a circuit (cable) given fire induced failure is a hot short. A conditional probability and a hot short duration probability are assigned using industry guidance published in NUREG-7150, Volume 2 (Reference 8). The uncertainty values specified in NUREG-7150, Volume 2 are based on fire test data.	The use of hot short failure probability and duration probability is based on fire test data and associated consensus methodology published in NUREG-7150, Volume 2. Based on the discussion of sources of uncertainty and the discussion above, it is concluded that the methodology for the Circuit Failure Mode Likelihood Analysis task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
11	Detailed Fire Modeling	The application of fire modeling technology is used in the FPRA to translate a fire initiating event into a set of consequences (fire induced failures). The performance of the analysis requires a number of key input parameters. These input parameters include the heat release rate (HRR) for the fire, the growth rate, the damage threshold for the targets, and response of plant staff (detection, fire control, fire suppression). The fire modeling methodology itself is largely empirical in some respects and consequently is another source of uncertainty. For a given set of input parameters, the fire modeling results (temperatures as a function of distance from the	Consensus modeling approach is used for the Detailed Fire Modeling. The methodology for the Detailed Fire Modeling task does not introduce any epistemic uncertainties that affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no additional RMAs are required to address this item.

Key Assumptions and Sources of Uncertainty

Table E9-3: Fire PRA Sources of Model Uncertainty

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
		fire) are characterized as having some distribution (aleatory uncertainty). The epistemic uncertainty arises from the selection of the input parameters (specifically the HRR and growth rate) and how the parameters are related to the fire initiating event. While industry guidance is available, that guidance is derived from laboratory tests and may not necessarily be representative of randomly occurring events. The fire modeling results using these input parameters are used to identify a zone of influence (ZOI) for the fire and cables/equipment within that ZOI are assumed to be damaged. In general, the guidance provided for the treatment of fires is conservative and the application of that guidance retains that conservatism. The resulting risk estimates are also conservative.	

Key Assumptions and Sources of Uncertainty

Table E9-3: Fire PRA Sources of Model Uncertainty			
Task #	Description	Sources of Uncertainty	Disposition for RICT Application
12	Post-Fire Human Reliability Analysis	The Human Error Probabilities (HEPs) used in the FPRA were adjusted to consider the additional challenges that may be present given a fire. The HEPs included the consideration of degradation or loss of necessary cues due to fire. Given the methodology used, the impact of any remaining uncertainties is expected to be small.	The HEPs include the consideration of degradation or loss of necessary cues due to fire. The fire risk importance measures indicate that the results are somewhat sensitive to HRA model and parameter values. The LGS FPRA model HRA is based on industry consensus modeling approaches for its HEP calculations, so this is not considered a significant source of epistemic uncertainty. Assuming no credit for operator response is not realistic. However, the TSTF-505 procedure will require appropriate risk management action (RMA) focus on human performance for RICT entry, e.g., including an operator briefing on the significant human actions in the PRA that are pertinent to the configuration. Refer to Enclosure 12 for additional discussion on RMAs.

Key Assumptions and Sources of Uncertainty

Table E9-3: Fire PRA Sources of Model Uncertainty			
Task #	Description	Sources of Uncertainty	Disposition for RICT Application
13	Seismic-Fire Interactions Assessment	Since this is a qualitative evaluation, there is no quantitative impact with respect to the uncertainty of this task.	The qualitative assessment of seismic induced fires should not be a source of model uncertainty as it is not expected to provide changes to the quantified FPRA model. A conservative seismic hazard penalty is already applied to all RICT calculations to account for seismic risk impact. Based on the discussion of sources of uncertainty and the discussion above, it is concluded that the methodology for the Seismic-Fire Interactions Assessment task does not introduce any epistemic uncertainties that affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
14	Fire Risk Quantification	As the culmination of other tasks, most of the uncertainty associated with quantification has already been addressed. The other source of uncertainty is the selection of the truncation limit. However, the selected truncation was confirmed to be consistent with the requirements of the PRA Standard.	The selected truncation was confirmed to be consistent with the requirements of the PRA Standard. Based on the discussion of sources of uncertainty and the discussion above, it is concluded that the methodology for the Fire Risk Quantification task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

Key Assumptions and Sources of Uncertainty

Table E9-3: Fire PRA Sources of Model Uncertainty			
Task #	Description	Sources of Uncertainty	Disposition for RICT Application
15	Uncertainty and Sensitivity Analyses	This task does not introduce any new uncertainties. This task is intended to address how the fire risk assessment could be impacted by the various sources of uncertainty.	This task does not introduce any new uncertainties. This task is intended to address how the fire risk assessment could be impacted by the various sources of uncertainty. Based on the discussion of sources of uncertainty and the discussion above, it is concluded that the methodology for the Uncertainty and Sensitivity Analyses task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
16	FPRA Documentation	This task does not introduce any new uncertainties to the fire risk.	This task does not introduce any new uncertainties to the fire risk as it outlines documentation requirements. Based on the discussion of sources of uncertainty and the discussion above, it is concluded that the methodology for the FPRA documentation task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

5. References

1. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, dated October 12, 2012 (ADAMS Accession No. ML12286A322).

2. NUREG-1855, “Guidance on the treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making,” Main Report, March 2009.

3. EPRI TR-1016737, “Treatment of Parameter and Model Uncertainty for Probabilistic Risk Assessments,” Electric Power Research Institute, Final Report, December 2008.

4. LG-PRA-014, Revision 4, "Limerick Generating Station Quantification Notebook,” July 2018.

5. LG-PRA-013, Revision 4, “Limerick Generating Station Summary Notebook,” July 2018

6. LG-PRA-005.04, “Condensate and Feedwater System Notebook,” Appendix E.

7. NUREG/CR-6850 (also EPRI 1011989), “Fire PRA Methodology for Nuclear Power Facilities,” September 2005, with Supplement 1 (EPRI 1019259), September 2010.

8. “Joint Assessment of Cable Damage and Quantification of Effects from Fire (JACQUE-FIRE), Volume 2: Expert Elicitation Exercise for Nuclear Power Plant Fire-Induced Electrical Circuit Failure,” Final Report, NUREG/CR-7150, Vol. 1, EPRI 3002001989, U.S. NRC and Electric Power Research Institute, May 2014.

9. “Nuclear Power Plant Fire Ignition Frequency and Non-Suppression Probability Estimation Using the Updated Fire Events Database, United States Fire Event Experience Through 2009,” NUREG-2169/EPRI 3002002936, U.S. NRC and Electric Power Research Institute, January 2015.

10. "Refining and Characterizing Heat Release Rates from Electrical Enclosures During Fire (RACHELLE-FIRE), Volume 1: Peak Heat Release Rates and Effect of Obstructed Plume,” NUREG-2178 Vol. 1/ EPRI 3002005578, U.S. NRC and Electric Power Research Institute, Draft Report for Comment, April 2015.

ENCLOSURE 10

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

<u>Program Implementation</u>

Program Implementation

1. Introduction

Section 4.0, Item 11 of the NRC Final Safety Evaluation (Reference 1) for NEI 06-09-A, Revision 0 (Reference 2) requires that the license amendment request (LAR) provide a description of the implementing programs and procedures regarding the plant staff responsibilities for the Risk Managed Technical Specifications (RMTS) implementation, and specifically discuss the decision process for risk management action (RMA) implementation during a Risk-Informed Completion Time (RICT).

This enclosure provides a description of the implementing programs and procedures regarding the plant staff responsibilities for the RICT Program, including training of plant personnel, and specifically discusses the decision process for RMA implementation during extended Completion Times (CT).

2. RICT Program and Procedures

Exelon will develop a program description and implementing procedures for the RICT Program. The program description will establish the management responsibilities and general requirements for risk management, training, implementation, and monitoring of the RICT program. More detailed procedures will provide specific responsibilities, limitations, and instructions for implementing the RICT program. The program description and implementing procedures will incorporate the programmatic requirements for RMTS included in NEI 06-09-A. The program will be integrated with the online work control process. The work control process currently identifies the need to enter a LCO Action statement as part of the planning process and will additionally identify whether the provisions of the RICT program are required for the planned work. The risk thresholds associated with 10CFR50.65(a)(4) will be coordinated with the RICT limits. The maintenance rule performance monitoring provisions and Mitigating System Performance Index (MSPI) thresholds will assist in controlling the amount of risk expended in use of the RICT program.

The Operations Department (licensed operators) is responsible for compliance with the TS and will be responsible for implementation of RICTs and RMAs. Entry into the RICT program will require management approval prior to pre-planned activities and as soon as practicable following emergent conditions.

The procedures for the RICT program will address the following attributes consistent with NEI 06-09-A:

- Plant management positions with authority to approve entry into the RICT Program.
- Important definitions related to the RICT Program.
- Departmental and position responsibilities for activities in the RICT Program.
- Plant conditions for which the RICT Program is applicable.
- Limitations on implementing RICTs under voluntary and emergent conditions.
- Implementation of the RICT Program 30-day back stop limit.
- Use of the Real-Time Risk tool.

- Guidance on recalculating RICT and risk management action time (RMAT) within 12 hours or within the most limiting front-stop CT after a plant configuration change.
- Requirements to identify and implement RMAs when the RMAT is exceeded or is anticipated to be exceeded, and to consider common cause failure potential in emergent RICTs.
- Guidance on the use of RMAs including the conditions under which they may be credited in RICT calculations.
- Conditions for exiting a RICT.
- Requirements for training on the RICT Program.
- Documentation requirements related to individual RICT evaluations, implementation of extended CTs, and accumulated annual risk.

3. RICT Program Training

The scope of training for the RICT Program will include rules for the new TS program, Real-Time Risk tool software, TS Actions included in the program, and procedures. This training will be conducted for the following Exelon personnel:

Site Personnel

- Operations Director
- Operations Personnel (Licensed and Non-Licensed)
- Operations Training
- Outage Manager
- On-line Manager
- Planning and Scheduling Personnel
- Work Week Managers
- Regulatory Assurance Personnel
- Selected Maintenance Personnel
- Engineering
- Risk Management
- Other Selected Management

Corporate Personnel

- Operations Corporate Functional Area Manager
- Fleet Outages Corporate Functional Area Manager
- Licensing Management and Personnel
- Risk Management Personnel and Managers
- Training Management and Personnel
- Other Selected Management

Training will be carried out in accordance with Exelon training procedures and processes. These procedures were written based on the Institute of Nuclear Power Operations (INPO) Accreditation (ACAD) requirements, as developed and maintained by the National Academy for Nuclear Training. Exelon has planned three levels of training for implementation of the RICT Program. They are described below:

Program Implementation

Level 1 Training

This is the most detailed training. It is intended for the individuals who will be directly involved in the implementation of the RICT Program. This level of training includes the following attributes:

- Specific training on the revised TS
- Record keeping requirements
- Case studies
- Hands-on experience with the Real-Time Risk tool for calculating RMAT and RICT
- Identifying appropriate RMAs
- Common cause failure RMA considerations in emergent RICTs
- Other detailed aspects of the RICT Program

Level 2 Training

This training is applicable to plant management positions with authority to approve entry into the RICT Program, as well as supervisors, managers, and other personnel who will closely support RICT implementation. These individuals need a broad understanding of the purpose, concepts, and limitations of the RICT Program. Level 2 training is significantly more detailed than Level 3 training (described below), but it is different from Level 1 training in that hands-on time with the Real-Time Risk tool, case studies, and other specifics are not required.

Level 3 Training

This training is intended for the remaining personnel who require an awareness of the RICT Program. These employees need basic knowledge of RICT Program requirements and procedures. This training will cover RICT Program concepts that are important to disseminate throughout the organization.

4. References

1. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,'" dated May 17, 2007 (ADAMS Accession No. ML071200238).

2. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, dated October 12, 2012 (ADAMS Accession No. ML12286A322).

ENCLOSURE 11

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

Monitoring Program

Monitoring Program

1. Introduction

Section 4.0, Item 12 of the NRC Final Safety Evaluation (Reference 1) for NEI 06-09-A Revision 0 (Reference 2) requires that the license amendment request (LAR) provide a description of the implementation and monitoring program as described in Regulatory Guide (RG) 1.174, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Revision 1, (Reference 3) and NEI 06-09-A Revision 0. (Note that RG 1.174, Revision 2 (Reference 4), issued by the NRC in May 2011, made editorial changes to the applicable section referenced in the NRC safety evaluation for Section 4.0, Item 12.)

This enclosure provides a description of the process applied to monitor the cumulative risk impact of implementation of the Risk-Informed Completion Time (RICT) Program, specifically the calculation of cumulative risk of extended Completion Times (CTs). Calculation of the cumulative risk for the RICT Program is discussed in Step 14 of Section 2.3.1 and Step 7.1 of Section 2.3.2 of NEI 06-09-A, Risk Informed Technical Specifications Initiative 4b. General requirements for a Performance Monitoring Program for risk-informed applications are discussed in Regulatory Guide (RG) 1.174, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant Specific Changes to the Licensing Basis, Element 3.

2. Description of Monitoring Program

The RICT Program will require calculation of cumulative risk impact at least every refueling cycle, not to exceed 24 months, consistent with the guidance in NEI 06-09-A, Revision 0. For the assessment period under evaluation, data will be collected for the risk increase associated with each application of an extended CT for both core damage frequency (CDF) and large early release frequency (LERF), and the total risk will be calculated by summing all risk associated with each RICT application. This summation is the change in CDF or LERF above the zero maintenance baseline levels during the period of operation in the extended CT (i.e., beyond the front-stop CT). The change in risk will be converted to average annual values.

The total average annual change in risk for extended CTs will be compared to the guidance of RG 1.174, Revision 2, Figures 4 and 5, acceptance guidelines for CDF and LERF, respectively. If the actual annual risk increase is acceptable (i.e., not in Region I of Figures 4 and 5 of RG 1.174, Revision 2), then RICT Program implementation is acceptable for the assessment period. Otherwise, further assessment of the cause of exceeding the acceptance guidelines of RG 1.174 and implementation of any necessary corrective actions to ensure future plant operation is within the guidelines will be conducted under the corrective action program.

The evaluation of cumulative risk will also identify areas for consideration, such as:

- RICT applications that dominated the risk increase
- Risk contributions from planned vs. emergent RICT applications
- Risk Management Actions (RMA) implemented but not credited in the risk calculations
- Risk impact from applying RICT to avoid multiple shorter duration outages
- Any specific RICT application that incurred a large proportion of the risk

Monitoring Program

Based on a review of the considerations above, corrective actions will be developed and implemented as appropriate. These actions may include:

- Administrative restrictions on the use of RICTs for specific high-risk configurations
- Additional RMAs for specific configurations
- Rescheduling planned maintenance activities
- Deferring planned maintenance to shutdown conditions
- Use of temporary equipment to replace out-of-service systems, structures, or components (SSC)
- Plant modifications to reduce risk impact of future planned maintenance configurations

In addition to impacting cumulative risk, implementation of the RICT Program may potentially impact the unavailability of SSCs. The Maintenance Rule (MR) monitoring programs under 10 CFR 50.65 provide for evaluation and disposition of unavailability impacts which may be incurred from implementation of the RICT Program. The SSCs in the scope of the RICT Program which are also in the scope of the MR allows the use of the MR Program.

The monitoring program for the MR, along with the specific assessment of cumulative risk impact described above, serve as the Implementation and Monitoring Program for the RICT Program as described in Element 3 of RG 1.174 and NEI 06-09-A.

3. References

1. Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, 'Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,'" dated May 17, 2007 (ADAMS Accession No. ML071200238).

2. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, dated October 12, 2012 (ADAMS Accession No. ML12286A322).

3. Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1, November 2002.

4. Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 2, May 2011.

5. Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications," Revision 1, May 2011.

ENCLOSURE 12

License Amendment Request

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b."

<u>Risk Management Action Examples</u>

Risk Management Action Examples

1. Introduction

This enclosure describes the process for identification and implementation of Risk Management Actions (RMAs) applicable during extended Completion Times (CTs) and provides examples of RMAs. RMAs will be governed by plant procedures for planning and scheduling maintenance activities. The procedures will provide guidance for the determination and implementation of RMAs when entering the Risk-Informed Completion Time (RICT) Program consistent with the guidance provided in NEI 06-09-A, Revision 0 (Reference 1).

2. Responsibilities

For planned entries into the RICT Program, Work Management is responsible for developing the RMAs with assistance from Operations and Risk Management. Operations is responsible for approval and implementation of RMAs. For emergent entry into extended CTs, Operations is also responsible for developing the RMAs.

3. Procedural Guidance

For planned maintenance activities, implementation of RMAs will be required if it is anticipated that the risk management action time (RMAT) will be exceeded. For emergent activities, RMAs must be implemented if the RMAT is reached. Also, if an emergent event occurs requiring recalculation of a RMAT already in place, the procedure will require a reevaluation of the existing RMAs for the new plant configuration to determine if new RMAs are appropriate. These requirements of the RICT Program are consistent with the guidance of NEI 06-09-A.

For emergent entry into a RICT, if the extent of condition is not known, RMAs related to the success of redundant and diverse SSCs and reducing the likelihood of initiating events relying on the affected function will be developed to address the increased likelihood of a common cause event.

RMAs will be implemented in accordance with current procedures (e.g., References 2, 3, 4, 5) no later than the time at which an incremental core damage probability (ICDP) of 1E-6 is reached, or no later than the time when an incremental large early release probability (ILERP) of 1E-7 is reached. If, as the result of an emergent condition, the instantaneous core damage frequency (ICDF) or the instantaneous large early release frequency (ILERF) exceeds 1E-3 per year or 1E-4 per year, respectively, RMAs are also required to be implemented. These requirements are consistent with the guidelines of NEI 06-09-A.

By determining which structures, systems, or components (SSCs) are most important from a CDF or LERF perspective for a specific plant configuration, RMAs may be created to protect these SSCs. Similarly, knowledge of the initiating event or sequence contribution to the configuration-specific CDF or LERF allows development of RMAs that enhance the capability to mitigate such events. The guidance in NUREG-1855 (Reference 6) and EPRI TR-1026511 (Reference 7) will be used in examining PRA results for significant contributors for the configuration, to aid in identifying appropriate compensatory measures (e.g., related to risk- significant systems that may provide diverse protection, or important support systems or human actions). Enclosure 9 identifies several areas of uncertainty in the internal events and fire PRAs that will be considered in defining configuration-specific RMAs when entering a RICT.

Risk Management Action Examples

If the planned activity or emergent condition includes a SSC that is identified to impact Fire PRA, as identified in the current Real-Time Risk Program, Fire PRA specific RMAs associated with that SSC will be implemented per the current plant procedure.

It is possible to credit RMAs in RICT calculations, to the extent the associated plant equipment and operator actions are modeled in the PRA; however, such quantification of RMAs is neither required nor expected by NEI 06-09-A. Nonetheless, if RMAs will be credited to determine RICTs, the procedure instructions will be consistent with the guidance in NEI 06-09-A.

NEI 06-09-A classifies RMAs into the three categories described below:

1) Actions to increase risk awareness and control.

- Shift brief
- Pre-job brief
- Training
- Presence of system engineer or other expertise related to the activity
- Special purpose procedure to identify risk sources and contingency plans

2) Actions to reduce the duration of maintenance activities.

- Pre-staging materials
- Conducting training on mock-ups
- Performing the activity around the clock
- Performing walk-downs on the actual system(s) to be worked on prior to beginning work

3) Actions to minimize the magnitude of the risk increase.

- Suspend or minimize activities on redundant systems
- Suspend or minimize activities on other systems that adversely affect the CDF or LERF
- Suspend or minimize activities on systems that may cause a trip or transient to minimize the likelihood of an initiating event that the out-of-service component is meant to mitigate
- Use temporary equipment to provide backup power, ventilation, etc.
- Reschedule other risk-significant activities

4. Examples

Representative examples of RMAs that may be considered during a RICT Program entry, to reduce the risk impact and ensure adequate defense-in-depth, for electrical equipment and for a Residual Heat Removal (RHR) Suppression Pool Cooling (SPC) loop out of service are provided below.

Risk Management Action Examples

4.1. Electrical Action Statements

The electrical loading of the 4KV 1E buses at Limerick Generating station is asymmetric primarily for the loading of the common cooling water systems and HVAC systems. These systems are the Emergency Service Water (ESW) system, the Residual Heat Removal Service Water (RHRSW) system, the standby gas treatment system (SGTS) and the control room emergency fresh air system (CREFAS). The CRD and Instrument air system for each unit are also powered by 2 of the 4 divisions as they are two train systems.

There are 4 4KV 1E buses per unit, D11, D12, D13and D14 on Unit 1 and D21, D22, D23 and D24 on Unit 2. SGTS trains are powered by buses D11 and D12 and CREFAS by D13 and D14. ESW is powered by Unit 1 buses D11 and D12 and Unit 2 buses D23 and D24. RHRSW is powered by Unit 1 buses D11 and D12 and Unit 2 buses D21 and D22.

4.1.1 For TS action 3.8.1.1.B, 2 EDGs inoperable, the most impactful combination would be the D11 and D12 EDGs which impact ESW, and RHRSW for both units in addition to the unit specific symmetric loads. The sample RICT calculation in Enclosure 1 yields a RICT duration of 29.3 days. Here the RMAs would be would include the actions required by TS 3.7.1.1.a.5 and 3.7.1.2.a.3, and 3.8.1.1.e.2. These all address confirmation of the operability of the remaining trains and assurance that the operability status of the affected supported systems is addressed.

Additional RMAs would include:

1. Actions to increase risk awareness and control.
   - Briefing of the on-shift Operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
   - Notification of the TSO of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
   - Proactive implementation of RMAs during times of high grid stress conditions, such as during high demand conditions.
2. Actions to reduce the duration of maintenance activities.
   - For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
   - Confirmation of parts availability prior to entry into a preplanned RICT.
3. Actions to minimize the magnitude of the risk increase.
   - Evaluation of weather conditions for threats to the reliability of offsite power supplies.

Risk Management Action Examples

- Deferral of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit.

- Deferral of planned maintenance or testing that affects the reliability of operable DGs and their associated support equipment which affect common system availability. Treat the remaining operable DGs as protected equipment.

- Deferral of planned maintenance or testing on redundant train safety systems. If testing or maintenance activities must be performed, a review of the potential risk impact will be performed.

- Implementation of 10 CFR 50.65(a)(4) fire-specific RMAs associated with the affected DGs.

4.1.2 TS action 3.8.1.1.f, one offsite source inoperable yields a 30-day back stopped RICT in Enclosure 1.

The RMAs for this RICT would, similar to the above, include:

1. Actions to increase risk awareness and control.

   - Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.

   - Notification of the TSO of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.

   - Proactive implementation of RMAs during times of high grid stress conditions prior to reaching the RMAT, such as during high demand conditions.

2. Actions to reduce the duration of maintenance activities.

   - For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability

   - Confirmation of parts availability prior to entry into a preplanned RICT.

   - Walkdown of work prior to execution.

3. Actions to minimize the magnitude of the risk increase.

   - Evaluation of weather conditions for threats to the reliability of remaining offsite power supplies.

   - Deferral of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit.

Risk Management Action Examples

- Protection of the remaining offsite source, including switchyard and transformer.
- Walkdown of operable switchyard for potential wind driven missiles.
- Deferral of planned maintenance or testing that affects the reliability of DGs and their associated support equipment which affect common system availability. Treat the remaining offsite source as protected equipment.
- Implementation of 10 CFR 50.65(a)(4) fire-specific RMAs associated with the affected offsite source.

4.1.3 TS action 3.8.3.1.a, one AC distribution system division not energized yields a 7.8-day RICT in Enclosure 1. Here the supported systems have no power supply. If it is at the highest level this would be a 4KV 1E bus de-energized.

The RMAs for this RICT would, similar to the above, include:

1. Actions to increase risk awareness and control.
   - Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
   - Briefing of the on-shift operations crew concerning the impact the de-energized equipment has on the potential response to plant events such as reduced number of ECCS pumps and control systems.
   - Notification of the TSO of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
   - Proactive implementation of RMAs during times of high grid stress conditions prior to reaching the RMAT, such as during high demand conditions.
   - For a planned RICT, prior to removal from service the actions in the associated loss of bus procedure would be reviewed and implemented.
2. Actions to reduce the duration of maintenance activities.
   - For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
   - Confirmation of parts availability prior to entry into a preplanned RICT.
   - Walkdown of work prior to execution.

Risk Management Action Examples

3. Actions to minimize the magnitude of the risk increase.

    - Deferral of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit.

    - Protection of the remaining electrical buses in that unit, and protection of the opposite unit buses that power the remaining pump in a common cooling water system loop. For example, if Unit 2 bus D23 was inoperable, the Unit D11 bus would be protected as the power supply to the other pump in the common A ESW loop.

    - Deferral of planned maintenance or testing that affects the reliability of DGs and their associated support equipment which affect common system availability for the remaining buses.

    - Implementation of 10 CFR 50.65(a)(4) fire-specific RMAs associated with the affected bus.

    - Place unaffected trains of systems into service. For example, if one of two instrument nitrogen compressors is powered by the affected bus, the other unaffected compressor would be placed in service to support containment atmosphere control. This would be done prior to entry into a planned RICT.

4.1.4 TS action 3.8.1.1.a.3, 2 battery chargers on one division. Here the associated battery has no supply and will begin to discharge.

The RMAs for this RICT would, similar to the above, include:

1. Actions to increase risk awareness and control.

    - Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of DC division and station blackout.

    - Briefing of the on-shift operations crew concerning the impact the DC division has on the potential response to plant events such as reduced control systems.

    - Prior to removal from service. If a Planned RICT, the actions in the associated loss of bus procedure would be reviewed and implemented.

    - Minimize activities that could trip the unit.

2. Actions to reduce the duration of maintenance activities.

    - For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.

    - Confirmation of parts availability prior to entry into a preplanned RICT.

Risk Management Action Examples

- Walkdown of work prior to execution.

3. Actions to minimize the magnitude of the risk increase.

    - Deferral of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit.
    - Protection of the remaining DC electrical buses in that unit. Protect opposite unit power supplies for remaining pumps in loop affected by the inoperable SSC
    - Provide alternate charging source to the battery via temporary charger or FLEX equipment.
    - Remove nonessential loads from battery to extend time voltage will remain above minimum required level.
    - Implementation of 10 CFR 50.65(a)(4) fire-specific RMAs associated with the affected bus.

4.2. RHR Suppression Pool Cooling

For TS Action 3.6.2.3.a, one suppression cooling loop inoperable, the RMAs would include the following.

1. Defer planned maintenance or testing activities on the redundant SPC loop and its associated support equipment and treat those systems as protected equipment.
2. Defer planned maintenance or testing that affects the reliability of those safety systems that provide a defense-in-depth, such as feedwater and containment venting. If testing or maintenance activities must be performed, a review of the potential risk impact will be performed.
3. Implement 10 CFR 50.65(a)(4) fire-specific RMAs associated with the affected SPC loop.
4. Minimize activities that add heat to the suppression pool.
5. Verify system alignment of remaining loop of SPC.

Risk Management Action Examples

5. References

1. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0, dated October 12, 2012 (ADAMS Accession No. ML12286A322).

2. Exelon Procedure OP-AA-201-012-1001, “Operations On-Line Fire Risk Management.”

3. LG-CRM-017, “Development of Risk Management Actions for the Inclusion of Fire Insights into Limerick Generating Station Configuration Risk Management Program.”

4. Exelon Procedure WC-AA-101-1006, “On-Line Risk Management and Assessment.”

5. Exelon Procedure OP-AA-108-117, “Protected Equipment Program.”

6. NUREG-1855, “Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making,” U.S. Nuclear Regulatory Commission, March 2009.

7. EPRI TR-1026511, “Practical Guidance on the Use of Probabilistic Risk Assessment in Risk-Informed Applications with a Focus on the Treatment of Uncertainty,” Technical Update, Electric Power Research Institute, December 2012.