200 Exelon Way
Kennett Square, PA 19348
www.ConstellationEnergy.com

ATTACHMENTS 3, 4, 5, 6 AND 8.2 OF ENCLOSURE 1 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

10 CFR 50.90

September 12, 2023

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

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: Resubmittal of License Amendment Request to Revise the Licensing and Design Basis to Incorporate the Replacement of Existing Safety-Related Analog Control Systems with a Single Digital Plant Protection System (PPS) – To Address Proprietary Issues with DOE INL HFE Reports

References:

1. Constellation Energy Generation, LLC (CEG) letter to the U.S. Nuclear Regulatory Commission (NRC), "License Amendment Request to Revise the Licensing and Design Basis to Incorporate the Replacement of Existing Safety-Related Analog Control Systems with a Single Digital Plant Protection System (PPS)," dated September 26, 2022 (NRC Agencywide Documents Access and Management System (ADAMS) Accession No. ML22269A5690).

2. U.S. Nuclear Regulatory Commission (NRC) letter to Constellation Energy Generation, LLC (CEG), “Limerick Generation Station, Unit Nos. 1 and 2 – Acceptance of Requested Licensing Action Re: Replacement of Existing Safety Related Analog Control Systems with a Single Digital Plant Protection System (EPID L-2022-LLA-0140),” dated December 9, 2022 (ADAMS Accession No. ML22339A064).

3. Email Letter from B.P. Jain, U.S. Nuclear Regulatory Commission to F. J. Mascitelli, Constellation Energy Generation, LLC (CEG), “Action: Limerick LAR - OUO information in Non-Proprietary LAR (EPID: L-2022-LLA-0140), dated January 19, 2023

Per Reference 1 and in accordance with 10 CFR 50.90, Constellation Energy Generation, LLC (CEG) requested amendments to Renewed Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively. The proposed changes would revise the LGS licensing and design basis to incorporate a planned digital modification at LGS (i.e., the LGS Digital Modernization Project).

ATTACHMENTS 3, 4, 5, 6 AND 8.2 OF ENCLOSURE 1 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION –WITHHOLD UNDER 10 CFR 2.390. When separated from Attachments 3, 4, 5, 6 and 8.2 of Enclosure 1, this cover letter is decontrolled.

ATTACHMENTS 3, 4, 5, 6 AND 8.2 OF ENCLOSURE 1 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

The LGS Digital Modernization Project (DMP) will replace the existing analog control logic hardware of the Reactor Protection System (RPS) instrumentation, Nuclear Steam Supply Shutoff System (NSSSS) instrumentation, the Emergency Core Cooling System (ECCS) instrumentation, the Reactor Core Isolation Cooling (RCIC) System instrumentation, and the End-of-Cycle Recirculation Pump Trip (EOC-RPT) instrumentation with a new, single, digital control system. The new, single, digital control system (i.e., for RPS, NSSSS, ECCS, RCIC, and EOC-RPT) will be renamed the Plant Protection System (PPS).

In Reference 2, NRC provided their acceptance of the license amendment request (LAR) for further NRC review.

In Reference 3, NRC identified that in the non-proprietary LAR submittal package in Reference 1, Attachment 8 contained two DOE INL Reports (HFE Program Plan and the HFE Combined Workshop Results Summary Report (RSR)) that had DOE “Official Use Only” (OUO) Markings and should have been submitted in accordance with 10 CFR 2.390 and proprietary portion of the documents withheld from public disclosure.

Upon further review it was concluded that the HFE Program Plan, “INL/RPT-22-68693, "Human Factors Engineering Program Plan for Constellation Safety Related Instrumentation and Control Upgrades," July 2022, contained no proprietary information. However, the HFE Combined Workshop RSR, INL/RPT-22-68995, "Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report," July 2022, does contain CEG proprietary information.

Therefore, the original LAR (Reference 1) is being resubmitted (attached as Enclosure 1) with the HFE Program Plan and the redacted HFE Combined Workshop RSR included in the non-proprietary portion of the submittal, along with the CEG proprietary affidavit, and the proprietary HFE Combined Workshop RSR included in the proprietary portion of the submittal. DOE INL reports have had their OUO markings removed in the non-proprietary portion of the submittal.

In addition, Attachment 2, “Description of Proposed Technical Specifications,” contained in Reference 1 has been revised to remove Figure XX “Summary PPS Functional Diagram” for Unit 1 and Unit 2 TS Bases 3/4.3.1, PPS Overview sections, since Figure XX contains WEC proprietary information.

The Reference 1 cover letter and its Attachment 1 are attached. No changes were made to these portions of the Reference 1 submittal.

Attachment 2 of the Reference 1 submittal, which describes the proposed TS and TS bases changes, is attached. The only change to Attachment 2 is the removal of Figure XX from TS Bases markup as described above.

ATTACHMENTS 3, 4, 5, 6 AND 8.2 OF ENCLOSURE 1 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

Attachment 3 of Reference 1 (attached) provides the System Requirements Specification (SyRS) for the LGS PPS (i.e., WNA-DS-04899-GLIM-P, Revision 1). This attachment contains information proprietary to WEC, which is supported by an Affidavit signed by WEC, the owner of the information. No changes were made to this attachment as originally submitted in Reference 1.

Attachment 4 of Reference 1 (attached) provides the Failure Modes and Effects Analysis (FMEA) to support the proposed elimination of TS Surveillance Requirements (i.e., WNA-AR-01050-GLIMP, Revision 2). This attachment contains information proprietary to WEC which is supported by an Affidavit signed by WEC, the owner of the information. No changes were made to this attachment as originally submitted in Reference 1.

Attachment 5 of Reference 1 (attached) provides the LGS PPS System Design Specification (SyDS) (i.e.,WNA-DS-04900-GLIM-P, Revision 2). This attachment contains information proprietary to WEC, which is supported by an Affidavit signed by WEC, the owner of the information. No changes were made to this attachment as originally submitted in Reference 1.

Attachment 6 of Reference 1 (attached) provides the LGS PPS Primary Digital Components Qualification Summary Report (i.e., EQ-EV-386-GLIM-P, Revision 2). This attachment contains information proprietary to WEC which is supported by an Affidavit signed by WEC, the owner of the information. No changes were made to this attachment as originally submitted in Reference 1.

Attachment 7 of Reference 1 (attached) provides the Westinghouse Affidavit in support of Attachments 3, 4, 5, and 6. The Affidavit sets forth the basis on which the information may be withheld from public disclosure by the NRC and addresses, with specificity, the considerations listed in paragraph (b)(4) of Section 2.390 of the Commission's regulations. No changes were made to this attachment as originally submitted in Reference 1.

Attachment 8 of Reference 1 has been divided into two Attachments (8.1 and 8.2) to facilitate separation of CEG proprietary and non-proprietary documents.

> Attachment 8.1 provides LGS Digital Modernization Project - Application of Human Factors Engineering Principles, DOE INL/RPT-22-68693, "Human Factors Engineering Program Plan for Constellation Safety Related Instrumentation and Control Upgrades," July 2022, the DOE INL/RPT-22-68995, Rev 1, "Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report," May 3, 2023 (non-CEG proprietary), and the CEG proprietary affidavit for INL/RPT-22-68995.

ATTACHMENTS 3, 4, 5, 6 AND 8.2 OF ENCLOSURE 1 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

Attachment 8.2 provides the CEG proprietary DOE INL/RPT-22-68995, "Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report," July 2022 (CEG proprietary). An affidavit in support of this proprietary information is provided as Enclosure 2.

Attachment 9 of Reference 1 (attached) provides the Vendor Oversight Plan (VOP) Summary as discussed in DI&C ISG-06, Revision 2, subsection C.2.2.1. No changes were made to this attachment as originally submitted in Reference 1.

Attachment 10 of Reference 1 (attached) describes a Regulatory Commitment associated with this proposed change, as discussed in DI&C ISG-06, Revision 2, subsection C.2.2.3. No changes were made to this attachment as originally submitted in Reference 1.

This supplemental letter contains no new regulatory commitments.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), CEG is notifying the Commonwealth of Pennsylvania of this LAR supplemental letter by transmitting a copy of this letter to the designated State Official.

If you have any questions regarding this submittal, please contact Frank Mascitelli at Frank.Mascitelli@constellation.com.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 12th day of September 2023.

Respectfully,

David P. Helker
Sr. Manager - Licensing
Constellation Energy Generation, LLC

Enclosures:

1. Resubmittal of Reference 1 LAR to reflect changes to Attachment 2 and Attachment 8
2. Affidavit for Attachment 8.2 of Enclosure 1

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	w/o attachments 3, 4, 5, 6, 8.2

Enclosure 1

License Amendment Request Supplement

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

Resubmittal of Reference 1 LAR to reflect changes to Attachment 2 and Attachment 8

200 Exelon Way
Kennett Square, PA 19348
www.ConstellationEnergy.com

ATTACHMENTS 3, 4, 5, and 6 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

10 CFR 50.90

September 26, 2022

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

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 the Licensing and Design Basis to Incorporate the Replacement of Existing Safety-Related Analog Control Systems with a Single Digital Plant Protection System (PPS)

References:
1. Exelon Generation Company, LLC letter to the U.S. Nuclear Regulatory Commission (NRC), "Letter-of-Intent to Submit a License Amendment Request for the Limerick Digital Modernization Project," (ADAMS Accession No. ML20346A026), dated December 11, 2020

2. NRC Digital Instrumentation and Control (DI&C) Interim Staff Guidance (ISG)-06, "Licensing Process," Revision 2

3. Constellation Energy Generation, LLC (CEG) letter to the NRC, "Review of Limerick Generating Station Defense in Depth and Diversity Common Cause Failure Coping Analysis, WNA-AR-01074-GLIM-P, Revision 1, February 2022," (ADAMS Accession No. ML22045A480), dated February 14, 2022

4. CEG letter to the NRC, "Review of Limerick Generating Station Defense in Depth and Diversity Common Cause Failure Coping Analysis, WNA-AR-01074-GLIM-P, Revision 2, July 2022, and the Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project, WCAP-18598-P, Revision 0, July 2022," dated August 12, 2022 (ADAMS Accession No. ML22224A146)

5. NRC Meeting Notice, "Presubmittal Meeting with Constellation Energy Generation, LLC About Planned Digital Modernization License Amendment Request for Limerick Generating Station, Units 1 and 2," (ADAMS Accession No. ML22250A475), dated August 25, 2022

ATTACHMENTS 3, 4, 5, and 6, HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390. When separated from Attachments 3, 4, 5, and 6, this cover letter is decontrolled.

ATTACHMENTS 3, 4, 5, and 6 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

In accordance with 10 CFR 50.90, Constellation Energy Generation, LLC (CEG) requests amendments to Renewed Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively. The proposed changes will revise the LGS licensing and design basis to incorporate a planned digital modification at LGS (i.e., the LGS Digital Modernization Project). Attachment 1 to this letter provides an evaluation of the proposed changes. Incorporation of the modification into the LGS licensing and design basis will also result in changes to the LGS Technical Specifications (TS) (i.e., Appendix A to Renewed Facility Operating License Nos. NPF-39 and NPF-85). The proposed TS changes are included and described in Attachment 2. Draft changes to the LGS Updated Final Safety Analysis Report (UFSAR) will be available for NRC audit.

The LGS Digital Modernization Project will replace the existing analog control logic hardware of the Reactor Protection System (RPS) instrumentation, Nuclear Steam Supply Shutoff System (NSSSS) instrumentation, the Emergency Core Cooling System (ECCS) instrumentation, the Reactor Core Isolation Cooling (RCIC) System instrumentation, and the End-of-Cycle Recirculation Pump Trip (EOC-RPT) instrumentation with a new single digital control system. The new single digital control system (i.e., for RPS, NSSSS, ECCS, RCIC, and EOC-RPT) will be renamed the Plant Protection System (PPS).

The scope of the PPS modification also includes upgrading the Redundant Reactivity Control System (RRCS) with the Westinghouse Ovation programmable logic controller (PLC) platform. The RRCS performs the functions required to comply with the Anticipated Transient Without Scram (ATWS) rule (i.e., 10 CFR 50.62) and is currently classified as safety-related. The proposed change reclassifies RRCS to non-safety-related, consistent with the system classification requirements of 10 CFR 50.62. Any additional diverse actuation functions that are needed as a result of the Defense in Depth and Diversity Common Cause Failure (D3 CCF) coping analysis will be implemented in the new Ovation-based RRCS.

In addition, based on historical RRCS operational issues at LGS that have challenged plant operations, and have the potential to complicate reactor level control during an ATWS, CEG has chosen to eliminate the automatic RRCS feedwater runback (FWRB) function as part of the PPS modification, while retaining the manual FW pump trip function.

Similarly, based on the potential for ambient temperature swings in the Turbine Enclosure (TE) for reasons other than actual main steam leaks, which could potentially result in exceeding the TE Main Steam Line (MSL) tunnel area temperature setpoint and cause an unnecessary Group I isolation, CEG has elected to include elimination of the automatic isolation function for TE - MSL Tunnel Temperature – High in the modification and the addition of TS-required manual actions.

ATTACHMENTS 3, 4, 5, and 6 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

CEG has selected Westinghouse Electric Company (WEC) to provide the new digital system. The new system will be based on the Nuclear Regulatory Commission (NRC) - approved WEC Common Q platform, (i.e., "Common Qualified Platform Topical Report," WCAP-16097-P-A, Revision 4).

In Reference 1, CEG submitted a letter-of-intent (LOI) to the NRC that described a planned digital instrumentation and control (DI&C) license amendment request (LAR) for the LGS Modernization Project, indicating that the LAR would be developed and submitted in accordance with the Alternate Review Process (ARP) guidance in NRC DI&C Interim Staff Guidance (ISG)-06 (Reference 2). As recommended in DI&C ISG-06, CEG participated in 12 pre-submittal meetings with the NRC to discuss the proposed license amendments, including the use of the ARP. CEG has developed this LAR in accordance with the ARP guidance in DI&C ISG-06 (i.e., Sections C.2.1 "Details of License Amendment Request Content" and C.2.2 "Licensee Prerequisites for the Alternate Review Process Licensing Process").

In Reference 4, CEG submitted proprietary and non-proprietary versions of WCAP-18598-P, "PPS Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project" (LTR). The LTR, in concert with Attachments 1 through 10 of this LAR address the aspects of DI&C-ISG-06 that pertain to the ARP described in Section C.2, as well as the applicable parts of Section D, "Review Areas for the License Amendment Process." The LTR table of contents provides a cross-referenced listing, for each section and subsection of the LTR, to the required information specified in DI&C ISG-06, Section D.

NUREG-0800, "NRC Standard Review Plan (SRP)," Branch Technical Position (BTP) 7-19, "Guidance for Evaluation of Defense in Depth and Diversity to Address Common-Cause Failure Due to Latent Design Defects in Digital Safety Systems," requires performance of a Defense in Depth and Diversity (D3) assessment of a proposed safety-related digital I&C system to demonstrate that vulnerabilities to common-cause failures (CCFs) have been adequately addressed. In Reference 3, CEG submitted a D3 CCF coping analysis in support of the LGS PPS. Based on discussions with the NRC during a review audit of the document, CEG submitted a revised D3 CCF coping analysis in Reference 4.

CEG plans to implement the LGS Digital Modernization Project during the LGS Unit 1 20th refueling outage (Li1R20) and LGS Unit 2 18th refueling outage (Li2R18), currently scheduled to commence in April 2024 and April 2025, respectively. In order to initiate and complete equipment fabrication and factory acceptance testing prior to the start of the refueling outage, CEG requests approval of the proposed license amendments by March 1, 2024 (i.e., 15 months following a two-month acceptance review). The proposed TS changes will be implemented prior to start-up from Li1R20 and Li2R18.

ATTACHMENTS 3, 4, 5, and 6 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

- Attachment 1 to this letter provides an evaluation of the proposed changes.
- Attachment 2 describes the proposed TS changes. The description of the changes is divided, as appropriate, by TS Chapter, Specification, or group of Specifications. The description of each Chapter, Specification, or group of Specifications includes a markup of current TS, a discussion of the changes, a retyped/clean copy of the proposed TS, and proposed TS Bases markup pages (for information only).
- Attachment 3 provides the System Requirements Specification (SyRS) for the LGS PPS (i.e., WNA-DS-04899-GLIM-P, Revision 1). This attachment contains information proprietary to WEC, which is supported by an Affidavit signed by WEC, the owner of the information.
- Attachment 4 provides the Failure Modes and Effects Analysis (FMEA) to support the proposed elimination of TS Surveillance Requirements (i.e., WNA-AR-01050-GLIM-P, Revision 2). This attachment contains information proprietary to WEC which is supported by an Affidavit signed by WEC, the owner of the information.
- Attachment 5 provides the LGS PPS System Design Specification (SyDS) (i.e., WNA-DS-04900-GLIM-P, Revision 2). This attachment contains information proprietary to WEC, which is supported by an Affidavit signed by WEC, the owner of the information.
- Attachment 6 provides the LGS PPS Primary Digital Components Qualification Summary Report (i.e., EQ-EV-386-GLIM-P, Revision 2). This attachment contains information proprietary to WEC which is supported by an Affidavit signed by WEC, the owner of the information.
- Attachment 7 provides the Westinghouse Affidavit in support of Attachments 3, 4, 5, and 6. The Affidavit sets forth the basis on which the information may be withheld from public disclosure by the NRC and addresses, with specificity, the considerations listed in paragraph (b)(4) of Section 2.390 of the Commission's regulations.
- Attachment 8 provides the Human Factors Program Plan and the associated Results Summary Reports for the modification, as discussed in DI&C ISG-06, Revision 2, Section 2.5.1 and IEEE Std. 603-2018, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations," Clause 5.14.
- Attachment 9 provides the Vendor Oversight Plan (VOP) Summary as discussed in DI&C ISG-06, Revision 2, subsection C.2.2.1.
- Attachment 10 describes a Regulatory Commitment associated with this proposed change, as discussed in DI&C ISG-06, Revision 2, subsection C.2.2.3.

ATTACHMENTS 3, 4, 5, and 6 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

During the September 8, 2022 pre-submittal meeting with the NRC concerning this LAR (Reference 5), CEG indicated that the following documents associated with the LAR would be submitted on the specified dates:

- WNA-DS-04900-GLIM-P, Revision 3, LGS PPS System Design Specification (SyDS): February 17, 2023
- Human Factors Engineering (HFE) Conceptual Verification Results Summary Report (RSR): February 9, 2023

  The Conceptual Verification RSR will document the verification that the HSI design meets the requirements in the Validation and Verification reports. This will include an assessment of important human actions.
- HFE Preliminary Verification RSR: March 30, 2023

  The Preliminary Verification RSR will document the completion of preliminary validation activities including HSI design, and validation of credited manual actions, as described in NUREG-0800, "U.S. Nuclear Regulatory Commission Standard Review Plan," Chapter 18, "Human Factors Engineering," Attachment A, "Guidance for Evaluating Credited Manual Operator Actions."
- Seismic Equipment Qualification (EQ) Summary Report, Revision 0: April 18, 2023
- Environmental EQ Summary Report, Revision 1: May 3, 2023
- Electromagnetic Compatibility (EMC) EQ Summary Report, Revision 2: June 16, 2023

  The EQ Summary Reports listed above will provide the required information specified in DI&C-ISG-06, Section D.3.1, "Information to Be Provided." Specifically, this information will include:

  - Codes and Standards,
  - Equipment tested or analyzed,
  - Summary details of testing performed,
  - Reference to detailed test report(s)
  - Associated results,
  - Installation restrictions (if any), and
  - Conclusions.

ATTACHMENTS 3, 4, 5, and 6 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

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

If you have any questions regarding this submittal, then please contact Frank Mascitelli at Frank.Mascitelli@constellation.com.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 26th day of September 2022.

Respectfully,

Glen Kaegi

Glen Kaegi
Vice President, Nuclear Security and Licensing
Constellation Energy Generation, LLC

Attachments:
1. Evaluation of Proposed Changes
2. Description of Proposed Technical Specifications
3. WNA-DS-04899-GLIM-P, "Limerick Generating Station Plant Protection System Digital Modernization Project System Requirement Specification" (SyRS), Revision 1 (proprietary)
4. WNA-AR-01050-GLIM-P, "Limerick Generating Station Plant Protection System Failure Modes and Effects Analysis," Revision 2 (proprietary)
5. WNA-DS-04900-GLIM-P, "Limerick Generating Station Plant Protection System Digital Modernization Project System Design Specification (SyDS)," Revision 2 (proprietary)
6. EQ-EV-386-GLIM-P, "Comparison of Equipment Qualification Hardware Testing for Common Q Applications to Limerick Requirements," Revision 2 (proprietary)
7. CAW-22-049, Affidavit, Proprietary Information Notice, and Copyright in support of WNA-DS-04899-GLIM-P, Revision 1, WNA-AR-01050-GLIM-P, Revision 2, WNA-DS-04900-GLIM-P, Revision 2, and EQ-EV-386-GLIM-P (Attachments 3, 4, 5, and 6), dated September 20, 2022

ATTACHMENTS 3, 4, 5, and 6 TRANSMITTED HEREWITH CONTAIN PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

8. Human Factors Engineering

   LGS Digital Modernization Project - Application of Human Factors Engineering Principles

   INL/RPT-22-68693, "Human Factors Engineering Program Plan for Constellation Safety-Related Instrumentation and Control Upgrades," July 2022

   INL/RPT-22-68995 "Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report," July 2022

9. Vendor Oversight Plan (VOP) Summary

10. Regulatory Commitment

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	w/ attachments 1, 2, 7, 8, 9, and 10

ATTACHMENT 1

License Amendment Request
Limerick Generating Station, Units 1 and 2
NRC Docket Nos. 50-352 and 50-353

Evaluation of Proposed Changes

1.0 SUMMARY DESCRIPTION

In accordance with 10 CFR 50.90, Constellation Energy Generation, LLC (CEG) requests an amendment to Renewed Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively. The proposed changes will revise the LGS Technical Specifications (TS) and the Updated Final Safety Analysis Report (UFSAR) to incorporate a planned digital modification at LGS (i.e., the LGS Digital Modernization Project).

The LGS Digital Modernization Project will replace the existing analog control logic hardware of the Reactor Protection System (RPS) instrumentation, Nuclear Steam Supply Shutoff System (NSSSS) instrumentation, the Emergency Core Cooling System (ECCS) instrumentation, the Reactor Core Isolation Cooling (RCIC) system instrumentation, and the End-of-Cycle Recirculation Pump Trip system (EOC-RPT) instrumentation with a new single digital control system. The new single digital control system (i.e., for RPS, NSSSS, ECCS, RCIC, and EOC-RPT) will be renamed the Plant Protection System (PPS).

Incorporation of the modification into the LGS UFSAR will also result in changes to the LGS Technical Specifications (TS) (i.e., Appendix A to Renewed Facility Operating License Nos. NPF-39 and NPF-85). The proposed TS changes are provided in Attachment 2.

In Reference 1, Exelon Generation Company, LLC (i.e., the LGS licensee prior to CEG) submitted a letter-of-intent (LOI) to the U.S. Nuclear Regulatory Commission (NRC) that described a planned digital instrumentation and control (DI&C) license amendment request (LAR) for the LGS Modernization Project, indicating that the LAR would be developed and submitted in accordance with the Alternate Review Process (ARP) guidance in NRC DI&C Interim Staff Guidance (ISG)-06, "Licensing Process," Revision 2 (Reference 2).

As recommended in DI&C ISG-06, CEG participated in 12 pre-submittal meetings with the NRC to discuss the proposed license amendments, including the use of the ARP. The results of the first six meetings are summarized in References 3 through 8, while the meeting notices for the seventh through twelfth pre-submittal meetings are documented in References 9 through 14. The format and content of this LAR, including the attachments, are consistent with the DI&C-ISG-06 guidance for submittal and review of an ARP LAR.

CEG plans to implement the LGS Modernization Project during the LGS Unit 1 20th refueling outage (Li1R20) and the LGS Unit 2 18th refueling outage (Li2R18), currently scheduled to commence in April 2024 and April 2025, respectively. In order to initiate and complete equipment fabrication and factory acceptance testing prior to the start of the refueling outage, CEG requests approval of the proposed license amendments by March 1, 2024 (i.e., 15 months, following a two-month acceptance review). The proposed TS changes will be implemented prior to start-up from Li1R20 and Li2R18.

The scope of the PPS modification also includes upgrading the Redundant Reactivity Control System (RRCS) with the Westinghouse Ovation programmable logic controller (PLC) platform.

The RRCS performs the functions required to comply with the Anticipated Transient Without Scram (ATWS) rule (i.e., 10 CFR 50.62) and is currently classified as safety-related. The proposed change reclassifies RRCS to non-safety-related, consistent with the system classification requirements of 10 CFR 50.62. Any additional diverse actuation functions that are needed as a result of the Defense in Depth and Diversity Common Cause Failure (D3 CCF) coping analysis will be implemented in the new Ovation-based RRCS (i.e., the Diverse Protection System).

In addition, based on historical RRCS operational issues at LGS that have challenged plant operations, and have the potential to complicate reactor level control during an ATWS, CEG has chosen to eliminate the automatic RRCS feedwater runback (FWRB) function as part of the PPS modification, while retaining the manual FW pump trip function. This proposed change does not impact the LGS TS.

Similarly, based on the potential for ambient temperature swings in the Turbine Enclosure (TE) for reasons other than actual main steam leaks, which could potentially result in exceeding the TE Main Steam Line (MSL) tunnel area temperature setpoint and cause an unnecessary Group I isolation and subsequent reactor scram, CEG has elected to include elimination of the automatic isolation function for TE - MSL Tunnel Temperature – High in the modification and the addition of TS-required manual actions. This will necessitate a change to the LGS TS.

CEG has selected Westinghouse Electric Company (WEC) to provide the new digital system. The new system will be based on the NRC-approved WEC Common Q™ platform, (i.e., WCAP-16097-P-A, "Common Qualified Platform Topical Report," Revision 5 (Reference 15) and WCAP-16096-P-A, "Software Program Manual for Common Q Systems, Revision 5.1 (Reference 16).

As discussed above, CEG has developed this LAR in accordance with the ARP guidance in DI&C ISG-06 (i.e., Sections C.2.1 "Details of License Amendment Request Content" and C.2.2 "Licensee Prerequisites for the Alternate Review Process Licensing Process"). In Reference 17, CEG submitted a D3 CCF coping analysis in support of the LGS PPS. Based on discussions with the NRC during a review audit of the document, CEG submitted a revised D3 CCF coping analysis in Reference 18. By letter dated August 22, 2022, CEG submitted proprietary and non-proprietary versions of WCAP-18598-P, "PPS Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project" (LTR) (Reference 18). The LTR, in concert with the remainder of this attachment, and the additional attachments to this document address the aspects of DI&C-ISG-06 that pertain to the ARP described in Section C.2, as well as the applicable parts of Section D, "Review Areas for the LAR."

2.0 DETAILED DESCRIPTION

1. System Description and Operation

Reactor Protection System (RPS)
The RPS is classified as Safety Class 2, seismic Category I, Quality Group B, and electric Class 1E. The primary function of the RPS is to initiate a scram of the reactor through insertion of the control rods in order to:

- Prevent or limit fuel damage following abnormal transients
- Prevent damage to the Reactor Coolant Pressure Boundary (RCPB) as a result of excessive internal pressure; and
- Limit the uncontrolled release of radioactive materials from the fuel assembly or RCPB.

The RPS provides its function by monitoring certain plant parameters and, if one or more parameters exceed a specified limit, the RPS system functions to automatically insert control rods to terminate power production in the core. Control rod movement is performed by the Control Rod Drive (CRD) system.

When power is removed from the Scram Solenoid Pilot Valves (SSPVs) the de-energized valves exhaust air causing the control rods to insert. The automatic scram function of RPS is accomplished by monitoring the following plant parameters:

- Scram Discharge Volume (SDV) Water Level
- Scram Discharge Volume Water Level Float Switch (contact)
- Main Steam Line Isolation Valve (MSIV) position (contact)
- Main Turbine Stop Valve (TSV) Position (contact)
- Main Turbine Control Valve (TCV) Fast Closure (contact)
- Reactor Vessel Water Level
- Average Power Range Monitor (contact)
- Intermediate Range Monitors (contact)
- Drywell Pressure
- Reactor Vessel Pressure

In addition to generating automatic reactor scram signals in response to the parameters described above, the RPS provides the capability to manually scram the reactor through the use of Manual Scram Pushbutton switches or by placing the Reactor Mode Switch in the "Shutdown" position.

The RPS consists of two trip systems (A and B) each containing two channels of sensors and logic, for a total of four logic channels. The monitored parameters each have at least one input to each of the logic channels. The overall RPS logic requires that at least one channel in each trip system must be tripped in order to cause a scram. This is referred to as one out-of-two twice logic.

The RPS is a normally energized system. De-energizing any channel of the relay trip system in an electrical division places the trip system in that electrical division in a tripped condition (i.e., half-scram). This makes the RPS fail safe on loss of electrical power. For this reason, each electrical division is powered by an independent power source so that failure of one power source does not cause a full scram.

In addition to the various sensors, relays, and switches, the RPS includes the RPS inverter power sources which provide the RPS with the ability to remain energized (i.e., to prevent spurious trips) during short power loss transients, and the RPS bus protective devices which ensure that when power is available it is within the requirements of the bus loads.

The Design Basis functions are changing only with respect to coincidence trip logic. The current coincidence logic is described in LTR Section 3.1.1 and the new coincidence logic is described in LTR Section 3.2.

All the design basis events in UFSAR Chapter 15 and the reliance on the RPS trips are unchanged. The methodologies used in RPS trip logic remain unchanged.

Nuclear Steam Supply Shutoff System (NSSSS) Instrumentation
The purpose of the NSSSS, also referred to as the Primary Containment and Reactor Vessel Isolation Control System (PCRVICS) is to isolate the reactor pressure vessel, primary and secondary containments during accident conditions in order to limit the loss of reactor coolant and to prevent the release of radioactive materials to the environment in excess of 10 CFR 100 limits. The functional classification of the NSSSS is that of a safety related system. Its regulatory classification is that of an engineered safety feature (ESF) system.

The NSSSS initiates closure of various automatic isolation valves if monitored system variables exceed pre-established limits. This action limits the loss of coolant from the Reactor Coolant Pressure Boundary (RCPB) and the release of radioactive materials from the RCPB, the primary containment, and the reactor enclosure. The functional requirements associated with the NSSSS and its interfacing systems necessitate the following:

- Pipes or vents that penetrate primary containment and communicate directly with the reactor vessel have two isolation valves: one inside primary containment (i.e., inboard) and one outside primary containment (i.e., outboard).
- Pipes or vents that connect directly to the containment atmosphere and penetrate primary containment have two valves outside containment (i.e., inboard closest to containment and outboard further away from containment).

The NSSSS consists of seven functions implemented using eight logical isolation groups. These functions and groups are largely divided by the interfacing systems which are isolated by actuation of the NSSSS (e.g., Group IA provides main steam isolation, Group IIA provides isolation of the RHR system, etc.). LTR Table 2.2-1 describes the seven Groups, including the conditions that result in isolation, and the actuation logic.

Emergency Core Cooling System (ECCS) Instrumentation

The ECCS control and instrumentation is designed to meet the following functional safety design bases:

- Automatically initiate and control the ECCS to prevent fuel cladding temperatures from reaching 2200 °F.
- Respond to a need for emergency core cooling, regardless of the physical location of the malfunction or break that causes the need.
- The following safety design bases are specified to limit dependence on operator judgement in times of stress:
    - The ECCS responds automatically so that no action is required of plant operators within 10 minutes after a LOCA.
    - The performance of the ECCS is indicated by control room instrumentation.
    - Facilities for manual control of the ECCS are provided in the control room.

The ECCS instrumentation and controls are classified as Safety Class 2, seismic Category I, Quality Group B, and electric Class 1E.

The ECCS is comprised of independent core cooling systems that ensure the requirements of 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," are satisfied if a breach in the RCPB results in a loss of reactor coolant. The following systems are included in the ECCS, except where noted:

- High Pressure Coolant Injection (HPCI): The HPCI system provides and maintains an adequate coolant inventory inside the reactor vessel to limit fuel clad temperatures resulting from postulated small breaks in the RCPB. HPCI uses a large steam-driven pump to inject water into the Reactor Pressure Vessel (RPV) through the Core Spray Loop B Sparger and Feedwater (FW) Loop A Sparger.

- Automatic Depressurization System (ADS): The ADS acts to rapidly reduce reactor vessel pressure in a Loss of Coolant Accident (LOCA) situation in which the HPCI system fails to maintain reactor vessel water level. Under certain circumstances, HPCI may be unable to provide sufficient inventory to recover from a LOCA. However, if reactor pressure remains high concurrent with the LOCA, then the high capacity, low pressure ECCS pumps cannot inject until pressure has been lowered below their shutoff head pressure. This depressurization function is executed by the simultaneous opening of five Safety/Relief Valves (SRVs) by the ADS, based on conditions that indicate HPCI cannot maintain level sufficiently high while the RPV is still pressurized.

- Core Spray: The Core Spray system cools the fuel by spraying water on the core in the event of a LOCA associated with a wide range of pipe break sizes. This function is executed through the use of two mechanical divisions of two pumps each along with the requisite piping and valves. Electrically, the Core Spray system is divided into four divisions where each pump is powered from one emergency 4 KV bus, which can also be powered by an emergency diesel generator (EDG). Each division of the Core Spray system also includes a separate instrumentation and controls (I&C) architecture.

- Residual Heat Removal (RHR): The RHR system provides a number of different operating modes. The Low Pressure Coolant Injection (LPCI) mode is credited as part of the ECCS. LPCI acts to mitigate the consequences of a large break LOCA by injecting to the RPV at low reactor pressures. The RHR system also has non-ECCS modes that support containment cooling (suppression pool cooling, containment spray), shutdown cooling for decay heat removal, and other support functions (e.g., fuel pool cooling assist, alternate decay heat removal, and suppression pool level control through a radioactive waste system interface). The RHR system executes this function through the use of four divisions, each containing a pump along with the requisite piping, valves, and control systems. Two heat exchangers are also provided to support cooling capabilities.
- Reactor Core Isolation Cooling (RCIC): The RCIC system provides makeup water to the reactor vessel whenever the vessel is isolated from the main condenser and feedwater system. RCIC is not technically part of the ECCS suite of systems, although it performs similar functions. RCIC executes its safety function in a manner similar to HPCI through the use of a steam-driven pump that injects into the Feedwater Loop B Sparger. However, RCIC operates with a much smaller capacity than the HPCI system.
- The EDGs are designed to start and attain the required voltage and frequency within 10 seconds. The generator, static exciter, and voltage regulator are designed to permit the unit to accept the load and to accelerate the motors in the sequence and time requirements. LGS does not use an emergency load sequencer associated with the offsite and onsite power sources. Sequencing of loads on the Class 1E buses is achieved by individual time-delay relays for each load. The initiation of EDG Load Sequencing is a function that is included as part of the PPS. It is a limited function that initiates the load sequencing performed by existing plant instrumentation and controls not replaced by this modification.

Redundant Reactivity Control System (RRCS)
The 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 as a result of an anticipated operating transient. The RRCS logic is initiated when either the high reactor pressure or low reactor water level setpoints are reached. A signal is then sent to open the alternate rod insertion (ARI) valves that vent the CRD scram air header to insert the control rods into the reactor. A signal is also transmitted to the recirculation pump trip (RPT) breakers to trip the reactor recirculation pumps to reduce the reactor power. An initiation of the RRCS logic by high reactor pressure will cause the feedwater pumps to automatically runback. If reactor power has not decreased to a predetermined level, within a specified period of time, the RRCS logic will initiate a feedwater runback and the injection of a neutron poison solution into the reactor, via the Standby Liquid Control System (SLCS), and shut down the reactor.

The RRCS logic monitors reactor pressure and water level. The logic will cause the immediate energization of the ARI valves when either the reactor high pressure trip setpoint or low reactor water level 2 setpoint is reached, or the manual push buttons are armed and depressed. Energization of the RRCS ARI valves depressurizes the scram air header independent of the logic and vent valves of the RPS system.

Additional immediate RRCS response to the initiation signals include recirculation system pump motor breaker trip immediately if reactor high pressure is received or 9 seconds after a low reactor water level 2 signal is received. The high pressure initiation signal will initiate a feedwater runback after 25 seconds whether the feed pumps are in automatic or manual if the APRM "not downscale" trip signal is present. If power is not downscale after a 118-second time delay from the beginning of the ATWS event, the Reactor Water Cleanup (RWCU) system will be isolated and the SLCS will be automatically initiated. Ten minutes after the SLCS initiation, the RRCS can be reset, provided that RRCS actuation parameters have reset and the RRCS manual reset push buttons are depressed.

RRCS Alternate Rod Insertion (ARI)

The RRCS ARI signal to insert the control rods is generated in either of two separate divisions (i.e., two-out-of-two logic in a given division) and results in the energization of eight valves. Two of these valves vent the scram air supply line downstream of the backup scram valves. These RRCS valves also act to block the supply of air to the scram header. Check valves provide an air flow path around the valves that vent the scram air supply in the event one or more of the valves fails. Four additional RRCS valves vent the A and B scram header to the atmosphere. As the header depressurizes, the scram valves at each hydraulic control unit (HCU) will spring open, scramming the rods. Two RRCS valves vent the scram air header to the SDV drain and vent valves, closing these valves and isolating the SDV. All eight RRCS ARI valves are normally de-energized. Positive position of the ARI solenoid valves is indicated by voltage and plant air indications. The ARI signal can be reset after a 30-second time delay, provided that the high reactor pressure, low reactor water level 2, and manual initiation signals no longer exist.

RRCS Recirculation System Trips

The ATWS Recirculation Pump Trip (ATWS-RPT) System 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 2 or high reactor pressure 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 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 EOC-RPT System. 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 water 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 water level 2 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.

The trip circuits, including the sensors and the pump breakers, are Class 1E. The entire trip circuits may be tested during plant operation, except for opening of the pump breakers. ATWS-RPT circuitry is separated from non-Class 1E circuitry in accordance with the LGS separation criteria. Indicators and annunciators in the control room provide the status of the trip coils and the mechanical position of the pump circuit breakers. Actuation of the ATWS-RPT is recorded in the control room.

RRCS Feedwater Runback
The feedwater runback function mitigates the consequences of an ATWS event by stopping feedwater flow into the vessel, which reduces the core subcooling, thereby reducing the core power generation. Reactor high pressure combined with a 25-second time delay and APRM power 'not downscale' will initiate a feedwater runback. Feedwater flow will be reduced to 0% within 15 seconds. The logic to initiate feedwater runback is energized to trip and can be manually overridden 30 seconds after runback initiation. The runback reduces the input of cooler water flowing to the vessel. As average core coolant temperature increases, voids increase, reactivity decreases, and power is reduced.

The RRCS feedwater runback will occur whether the feed pumps are in automatic or in manual mode of control. The normal loss of signal interlock that prohibits changes in feedwater pump output during loss of signal conditions is disabled during an ATWS.

Standby Liquid Control System Initiation
Low reactor water level 2, reactor high pressure, or manual initiation of the RRCS immediately starts a timer. A signal will be sent to initiate the SLCS if, at the expiration of a 118-second time delay, the core power is not downscale as measured by the APRM system. Initiation of the SLCS requires start signals from both channels A and B of either division of RRCS. Receipt of these signals starts the two in-service pumps and causes the associated squibs to fire, opening the explosive valves. Both pumps will inject borated water into the vessel until the storage tank low level sensors, arranged in two-out-of-two logic, trip the pumps. The SLCS pump control switches can be used to manually stop SLCS pump injection.

Regulatory Guide (RG) 1.97 Indications
RG 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 2 is the licensing basis for LGS. The safety-related post-accident monitoring, RG 1.97 indications that are available to the Main Control Room (MCR) operators are described in LGS UFSAR Sections 7.5.1.4.2 "Post accident Monitoring" and Section 7.5.1.4.3, "Additional Instrumentation for Regulatory Guide 1.97 Variables."

2. Reason for Proposed TS Changes

CEG is implementing the LGS Digital Modernization Project, utilizing the WEC Common Q™ platform, in order to:

- Increase plant safety
- Increase equipment reliability
- Increase the quality of operations and maintenance

The PPS will achieve these objectives by reducing the potential for human error, increasing the speed and accuracy of operational decision-making, increasing full system availability and reliability, and enhancing self-diagnostic capabilities. The increase in availability and reliability will eliminate spurious half-scrams and single component vulnerabilities, as well as eliminate obsolete components. With respect to operation and maintenance of the equipment, the new PPS will improve the availability and quality of information available to the Main Control Room operators, improve configuration control, and reduce operator burden through automation.

Implementation of the Common Q™ system as a replacement for the existing analog control logic hardware of RPS, NSSSS instrumentation, ECCS instrumentation, RCIC System instrumentation, and the EOC-RPT instrumentation, with a new single digital control system, will introduce equipment and logic differences that will impact the current TS.

3. Current TS Requirements

The following current TS (CTS) sections are affected by this change:

- 1.0 Definitions
- 2.2.1 Limiting Safety System Settings
- 3/4.3.1 Reactor Protection System Instrumentation
- 3/4.3.2 Isolation Actuation Instrumentation
- 3/4.3.3 Emergency Core Cooling System Actuation Instrumentation
- 3/4.3.3.A Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation
- 3/4.3.4.1 Anticipated Transient Without Scram·Recirculation Pump Trip (ATWS-RPT) System Instrumentation
- 3/4.3.4.2 End-of-Cycle Recirculation Pump Trip (EOC-RPT) System Instrumentation
- 3/4.3.5 Reactor Core Isolation Cooling System Actuation Instrumentation
- 3/4.4.3.2 Operational Leakage
- 3/4.5.1 ECCS – Operating
- 3/4.7.3 Reactor Core Isolation Cooling System
- 3/4.10.8 Inservice Leak and Hydrostatic Testing
- 6.9.1.9 Core Operating Limits Report

TS 2.2.1 provides the list of RPS instrumentation setpoints (i.e., in Table 2.2.1-1).

TS 3/4.3.1 provides the limiting conditions for operation (LCOs), Actions, and Surveillance Requirements (SRs) necessary to preserve the ability of the RPS to perform its intended function even during periods when instrument channels may be out of service because of maintenance.

TS 3/4.3.2 provides the LCOs, Actions, and SRs to ensure the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the operability trip setpoints and response times for the NSSSS.

TS 3/4.3.3 provides the LCOs, Actions, SRs, trip setpoints and response times that will ensure effectiveness of the ECCS to mitigate the consequences of accidents that are beyond the ability of the operator to control.

TS 3/4.3.3.A provides the LCOs, Actions, and SRs for instrumentation to support LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC)," and the definition of Drain Time. RPV WIC is required in Operational Conditions (OPCONs) 4 and 5 to protect Safety Limit 2.1.4, and the fuel cladding barrier, to prevent the release of radioactive material to the environment should an unexpected draining event occur.

TS 3/4.3.4.1 provides the LCOs, Actions, SRs, trip setpoints and response times for the ATWS-RPT System instrumentation. The ATWS-RPT system establishes a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient.

TS 3/4.3.4.2 provides the LCOs, Actions, SRs, trip setpoints and response times for the EOC-RPT System instrumentation. The EOC-RPT system is a supplement to the reactor trip to reduce the likelihood of reactor vessel level decreasing to Level 2 during turbine trip and generator load rejection event.

TS 3/4.3.5 provides the LCOs, Actions, SRs, trip setpoints and response times for the RCIC system instrumentation. The RCIC System assures adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel.

TS 3/4.4.3.2 provides the LCOs, Actions, and SRs for allowable leakage rates from the reactor coolant system, based on the predicted and experimentally observed behavior of cracks in pipes.

TS 3/4.5.1 provides the LCOs, Actions, and SRs for the CS system, the LPCI mode of the RHR system, the HPCI system, and the ADS.

TS 3/4.7.3 provides the LCOs, Actions, and SRs for the RCIC system to assure that the system is able to provide 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 the ECCS.

TS 3/4.10.8 provides LCOs, Actions, Applicability, and SRs that permit certain reactor coolant pressure tests to be performed in OPCON 4 when the metallurgical characteristics of the RPV or plant-temperature control capabilities during these tests require the pressure testing at temperatures greater than 200°F (i.e., normally corresponding to OPCON 3).

TS 6.9.1.9 defines the requirement to establish a unit-specific core operating limits report for the current operating reload cycle, as well as identifies the operating limits.

4. <u>Description of Proposed TS Changes (to align with TOC)</u>

Attachment 2 describes the proposed TS changes that are necessary to fully implement the LGS PPS. The description of the changes is divided, as appropriate, by the proposed TS Chapter, Specification, or group of Specifications. Each division includes a markup of current TS, a discussion of the changes, a retyped/clean copy of the proposed TS for the specific Chapter or Specification, and proposed TS Bases markup pages (for information only). The retyped proposed TS pages are technically correct, but not "publication ready." Page numbers, page breaks, insertion of "intentionally blank" pages, indenting, table column spacing, etc., may change in the final approved version of the proposed TS changes. In addition, there are LARs under NRC review that affect some of the affected TS pages. CEG will submit final, "publication ready" TS pages prior to LAR approval, consistent with CEG's normal practice of providing final TS pages for other LARs.

In addition to the TS changes required to implement the proposed replacement of the existing RPS, NSSSS, ECCS, RCIC, and EOC-RPT analog control logic hardware with a new single digital control system (i.e., PPS), CEG is proposing to implement the following changes:

- Reclassification of RRCS to non-safety-related, consistent with the system classification requirements of 10 CFR 50.62. This proposed change does not impact the TS.
- Elimination of the RRCS feedwater runback logic on a reactor high pressure signal. This proposed change does not impact the TS.
- Elimination of TS 3.3.2, Tables 3.3.2-1 and 4.3.2-1, Function 1.g. – "Turbine Enclosure - Main Steam Line Tunnel Temperature – High," and addition of new TS 3/4.7.9, "Turbine Enclosure - Main Steam Line Tunnel Temperature." This proposed TS change is included in the Attachment 2 proposed TS change markups, retyped TS pages, and discussion of changes.

3.0 TECHNICAL EVALUATION

This LAR is intended to address all DI&C-ISG-06 content requirements for the ARP. Enclosure B to DI&C-ISG-06, "Information Provided in Support of a License Amendment Request for a Digital Instrumentation and Control Modification," provides a cross-reference to the descriptive material identified in the body of the DI&C-ISG-06 guidance document. This LAR addresses, as a minimum, items included in the Enclosure B "AR" column.

1. <u>DI&C-ISG-06 Alternate Review Process (ARP) LAR Contents</u>

   DI&C-ISG-06 Section C.2 describes the ARP. Section C.2.1 provides guidance for ARP LAR contents. A prerequisite for requesting LAR review using the ARP is to use digital equipment which has a topical report previously approved by the NRC. There is also an expectation that the topical report vendor will develop the system. For the LGS Modernization Project, CEG has selected the NRC-approved WEC Common Q™ digital platform.

   The WEC Common Q™ platform has two NRC-approved topical reports for: 1) the digital equipment; and 2) application software development process (References 13 and 14). The digital equipment topical report was recently re-reviewed by the NRC with approval issued in May 2021. Thus, the equipment proposed for the LGS PPS has been recently reviewed by the NRC. Note that Section 6 of the LTR (Reference 16), which addresses DI&C-ISG-06 Section D.5, describes any platform changes since NRC approval of the topical report. In addition, the LTR addresses all but one of the Plant-Specific Action Items (PSAIs) and the remaining Generic Open Items (GOI) included in the most recent NRC approval for both topical reports. WEC is contracted to develop the hardware and software system.

   This LAR also includes the following attachments to address items discussed in, or required by DI&C-ISG-06:

   - System Requirements Specification (SyRS), Revision 1 (Attachment 3) (Proprietary)
   - Failure Modes and Effects Analysis (FMEA), Revision 2 (Attachment 4) (Proprietary)
   - System Design Specification (SyDS), Revision 2 (Attachment 5) (Proprietary)
   - Equipment Qualification Hardware Testing for Common Q Applications to Limerick Requirements, Revision 2 (Attachment 6) (Proprietary)
   - Human Factors Engineering (HFE) (Attachment 8)
   - Vendor Oversight Plan (VOP) Summary (Attachment 9)
   - Regulatory Commitment (Attachment 10)

   Attachments 3 and 5 (i.e., the SyRS and SyDS) together fulfill the DI&C-ISG-06, Revision 2 criteria for submittal of a System Requirements Specification (i.e., D.2.3.3.1). The SyRS provides the complete set of functional requirements for the PPS, while the SyDS describes the system architecture requirements, based on the functional requirements in the SyRS. The system architecture requirements described in Revision 2 of the SyDS (i.e., Attachment

5) are based on Revision 0 of the SyRS. As part of the WEC design process, the SyRS has been revised; Attachment 3 provides SyRS Revision 1.

Revision 1 of the SyRS necessitates an additional revision to the SyDS (i.e., Revision 3). CEG has identified and evaluated the necessary changes to Revision 2 of the SyDS, the impact of these changes to the system architecture, and the impact of these changes on conformance with DI&C ISG-06, Revision 2 ARP requirements. CEG discussed these changes with the NRC during a pre-submittal meeting on September 8, 2022 (Reference 14).

Upon completion, CEG will submit SyDS Revision 3 as a supplement to this LAR. The expected completion date for SyDS Revision 3 is February 17, 2023.

During the September 8, 2022 pre-submittal meeting, CEG indicated that the following additional documents that support the LAR would be submitted on the specified dates:

- Human Factors Engineering (HFE) Conceptual Verification Results Summary Report (RSR): February 9, 2023

  The Conceptual Verification RSR will document the verification that the HSI design meets the requirements in the Validation and Verification reports. This will include an assessment of important human actions.

- HFE Preliminary Verification RSR: March 30, 2023

  The Preliminary Verification RSR will document the completion of preliminary validation activities including HSI design, and validation of credited manual actions, as described in NUREG-0800, "U.S. Nuclear Regulatory Commission Standard Review Plan," Chapter 18, "Human Factors Engineering," Attachment A, "Guidance for Evaluating Credited Manual Operator Actions."

- Seismic Equipment Qualification (EQ) Summary Report, Revision 0: April 18, 2023
- Environmental EQ Summary Report, Revision 1: May 3, 2023
- Electromagnetic Compatibility (EMC) EQ Summary Report, Revision 2: June 16, 2023

  The three EQ Summary Reports listed above will provide the required information specified in DI&C-ISG-06, Section D.3.1, "Information to Be Provided." Specifically, this information will include:

  - Codes and Standards,
  - Equipment tested or analyzed,
  - Summary details of testing performed,
  - Reference to detailed test report(s)
  - Associated results,
  - Installation restrictions (if any), and
  - Conclusions.

Both in DI&C-ISG-06 and in the public meetings held during its development, the NRC stressed the importance of licensees performing adequate vendor oversight of the digital platform vendor. The licensee has the primary responsibility to ensure that the vendor adheres to the lifecycle development process described in the LAR, NRC-approved vendor development process and other procurement information. The Vendor Oversight Plan (VOP), as currently executed, is used to ensure that the vendor executes the project, consistent with the LAR. A summary of the project-specific VOP is included in Attachment 9.

This ARP-based LAR is designed to be a single submittal provided to the NRC early in the project schedule. Thus, the LAR content is based on conceptual design, system requirements, and human-system interface requirements. Based on multiple pre-submittal meetings with the NRC, CEG has determined that this LAR contains sufficient "system design" information to demonstrate compliance with the regulatory requirements.

In addition, this ARP-based LAR is consistent with an NRC-approved precedent application of the ARP process. By letter dated July 23, 2020, as supplemented, Entergy Operations, Inc. (Entergy) requested a license amendment to implement a planned digital modification at Waterford Steam Electric Plant, Unit 3 (Waterford) (ADAMS Accession No. ML20205L588). Entergy submitted this LAR in accordance with the DI&C ISG-06, Revision 2 ARP guidance. The NRC approved the license amendment by letter and Safety Evaluation (SE) dated August 24, 2021 (ADAMS Accession Nos. ML21188A021 and ML21131A243).

<u>Licensee Prerequisites</u>

DI&C-ISG-06 Section C.2.2 describes the licensee prerequisites for use of the ARP. Item 1 states that the LAR should include a description of the licensee's VOP. The VOP, when executed, must ensure that the vendor (1) executes the project consistent with the LAR, and (2) uses an adequate software QA program. As described above, the VOP summary is included in Attachment 9. The VOP describes the licensee interactions with the vendor throughout the entire system development lifecycle to ensure the software and system development is in accordance with the NRC-approved software development process (Reference 16).

Section C.2.2, Item 2 states that the LAR should contain a reference to an NRC-approved topical report. Item 2 has two subparts. To address subpart a., the WEC Common Q™ platform has two NRC-approved topical reports (References 13 and 14). The LGS PPS application is within the scope of both topical reports. To address subpart b., WEC will be using the NRC-approved Common Q™ Software Program Manual (SPM) (Reference 16) as the framework for the design and development of the LGS Digital Modernization Project. This framework is a supplement to the WEC 10 CFR 50 Appendix B Quality Assurance program to specifically address digital I&C safety system development.

Section C.2.2 Item 3 addresses licensee regulatory commitments. This item has two subparts. Subpart a. states that the LAR should include regulatory commitments to complete the referenced topical reports' PSAIs. Sections 5 and 6 of the LTR disposition the applicable PSAIs, with one exception (i.e., SPM PSAI 5). In many instances, the PSAI response in the LTR references vendor oversight. Through this LAR, CEG will execute vendor oversight in accordance with the VOP (i.e., as summarized in Attachment 9). Based on PSAI disposition in the LTR, there is one regulatory commitment described in Attachment 10 to complete SPM PSAI 5.

2. Licensing Technical Report (LTR)

The LTR (Reference 16) directly addresses the requirements specified in DI&C-ISG-06 Sections D.1 to D.8 entitled "Information to be Provided." The LTR Table of Contents and the LTR section/subsection headings in the body of the LTR specify the applicable DI&C ISG-06 Section D information requirement that is addressed. The various major section and subsection headings in the LTR include either "(D.x)" and "(D.x.x)" to specify the specific DI&C-ISG-06 sections/subsections that are addressed. In addition, each LTR section includes a description of compliance to the applicable 10 CFR 50 Appendix A General Design Criteria, IEEE Std. 603-1991, IEEE Std. 7-4.3.2-2003, or other regulatory requirements listed in the corresponding DI&C-ISG-06 section.

As specified in DI&C-ISG-06, Section D.6, LTR Section 7 provides a matrix that summarizes compliance/conformance of the LGS PPS to IEEE Std. 603-1991 and IEEE Std. 7-4.3.2-2003 requirements, including a cross-reference to the applicable sections in the LTR that describe the compliance/conformance.

Although DI&C-ISG-06 Enclosure B does not include a requirement to provide a project-specific FMEA, the LGS-specific FMEA is included with the LAR (Attachment 4). This FMEA is included to support review of the LTR Appendix A Failure Modes, Effects, Diagnostics Analysis (FMEDA) for TS SR elimination. The LGS-specific FMEA is considered a "living document" per DI&C-ISG-06.

3. RRCS Reclassification

The scope of the PPS modification also includes upgrading the Redundant Reactivity Control System (RRCS) with the Westinghouse Ovation programmable logic controller (PLC) platform. The RRCS performs the functions required to comply with the Anticipated Transient Without Scram (ATWS) rule (i.e., 10 CFR 50.62) and is currently classified as safety-related. The proposed change reclassifies RRCS to non-safety-related, consistent with the system classification requirements of 10 CFR 50.62. Section 9.1 of the LTR provides additional detail supporting the RRCS reclassification.

4. Elimination of Automatic RRCS FW Runback Function

CEG has evaluated the potential impact, on LGS ATWS analysis results, of the automatic RRCS FW Runback (FWRB) function elimination. The results of that evaluation conclude that the ATWS acceptance criteria for maintaining reactor vessel integrity, containment integrity, and a coolable core geometry will continue to be met with elimination of the RRCS automatic FWRB function. In addition, the current LGS ATWS analysis conclusions will remain valid with the elimination. Section 9.6 of the LTR provides additional detail concerning the CEG evaluation and resulting conclusions.

5. <u>Elimination of Automatic Isolation Function for Turbine Enclosure (TE) – MSL Tunnel Temperature – High</u>

The automatic isolation function for TE - MSL Tunnel Temperature - High is eliminated. This elimination requires NRC approval to delete Function 1.g, "Turbine Enclosure - Main Steam Line Tunnel Temperature - High," from current Technical Specification (TS) instrumentation tables, exclude it from proposed TS instrumentation tables, and add a new proposed TS for the TE MSL tunnel temperature. A detailed description and justification for the elimination of the TE MSL Tunnel Temperature - High automatic isolation function is included in the Attachment 2 Discussion of Changes for TS 3.7.9.

The ambient temperature of the monitored TE MSL tunnel area can approach the isolation setpoint for reasons other than actual main steam leaks in the area, such as hot weather, reduced efficiency of the TE chillers, or instrument drift. If both TE MSL Tunnel Temperature - High trip systems were to initiate an isolation signal, a full Group 1 isolation and reactor trip would result. Group 1 isolation closes the MSIVs, resulting in a loss of heat sink, as well as rendering the main feedwater system unavailable for scram recovery.

The new TS establishes a maximum temperature for the TE MSL Tunnel and requires verification that the TE MSL tunnel temperature is below this value on a frequency controlled by the Surveillance Frequency Control Program (SFCP). This maximum temperature value will be established at the previous isolation trip setpoint. The initial frequency will be 24 hours. If the TE MSL tunnel maximum temperature exceeds the maximum allowable value, the Actions require immediate action to verify that no MSL leak exists, and periodic verification every 12 hours thereafter. If it cannot be verified that there is no MSL leakage or if the periodic verification is not performed, a plant shutdown is required.

6. <u>Defense-in-Depth and Diversity (D3) CCF Coping Analysis</u>

The existing (legacy) RPS, NSSSS, and ECCS functions are implemented using analog technology, so the change to an integrated PPS using the Common Q™ platform represents an analog-to-digital upgrade. As stated in NUREG-0800, "NRC Standard Review Plan (SRP)," Branch Technical Position (BTP) 7-19, "Guidance for Evaluation of Defense in Depth and Diversity to Address Common-Cause Failure Due to Latent Design Defects in Digital Safety Systems," the NRC requires performance of a Defense in Depth and Diversity (D3) assessment of a proposed safety-related digital I&C system to demonstrate that vulnerabilities to common-cause failures (CCFs) have been adequately addressed.

In Reference 15, CEG submitted a D3 CCF coping analysis in support of the LGS PPS. Based on discussions with the NRC during a review audit of the document, CEG submitted a revised D3 CCF coping analysis in Reference 16.

The LGS Digital Modernization D3 CCF Coping Analysis, WNA-AR-01074-GLIM-P, performs the following three analyses:

- An evaluation, for each LGS UFSAR Chapter 15 event, the plant coping ability with the assumption that the Common Q™ portion of the PPS is not available due to a CCF. This analysis defines the Diverse Protection System (DPS) functions needed to meet the coping acceptance criteria from BTP 7-19.

- An analysis defining the set of displays and controls located in the main control room for manual, system-level actuation of critical safety functions and monitoring of parameters that support the safety functions. The displays and controls are independent and diverse from the PPS Common Q™ system.
- A CCF Spurious Actuation Analysis that evaluates the potential for a PPS (as well as RRCS) system level spurious actuation and the extent the plant can cope with such an initiating event. Any additional diverse features needed to meet UFSAR design conditions are identified in the analysis.

These three analyses identify required functionality of the DPS. The D3 coping analysis also compares the diversity attributes between the Common Q™ digital platform and the Ovation platform that will implement the DPS functions.

In Reference 17, WEC submitted a generic Component Interface Module (CIM) diversity analysis in support of the LAR. This analysis provides an evaluation of the key design features of the CIM that are used to address the risk of CCF. The design features provide the basis for addressing the risk of CCF and eliminating CCF vulnerabilities from further consideration. This document evaluates the CIM design in a configuration that is used in a typical safety system application and is referenced in this LAR as part of the D3 assessment of the LGS PPS.

7. Factory Acceptance Test/Site Acceptance Test (FAT/SAT)

The purpose of the FAT, as described in the WEC SPM for Common Q™ Systems, is to demonstrate that the complete system is integrated and functional. The FAT, together with the documentation of the Verification and Validation (V&V) activities (e.g., module tests, unit tests, software code reviews, integration testing, and system validation testing, etc.) demonstrate full compliance to the requirements.

While not specifically required by the DI&C-ISG-06 ARP content requirements, the NRC safety evaluation (SE) for the Waterford ARP precedent acknowledged that the Entergy review of, and participation in the FAT was an integral part of Entergy's vendor oversight plan.

As described in Section 3 of the VOP Summary (Attachment 9), CEG procedure CC-AA-107, "Configuration Change Acceptance Testing Criteria," requires a review of the vendor test plan and the adequacy of the respective vendor test procedures against the functional and the contract requirements using CC-AA-107-1002, "Guidelines for Implementing Factory Acceptance Tests." CC-AA-107-1002 provides a guideline for specifying and implementing FATs to ensure the successful installation, commissioning and operation of equipment and systems manufactured and tested by vendors. CC-AA-107-1002 also includes guidance for integrating CEG engineering, maintenance, and operations personnel’s participation into the FAT.

Similar to the FAT performed for the Entergy license amendment, the NRC's review and approval of Entergy's response to WEC SPM PSAI-5 was based, in part, on a regulatory commitment to ensure that the SAT and installation test plans conform to the criteria of BTP 7-14, "Guidance on Software Reviews for Digital Computer-Based Instrumentation and

Control Systems." Section 5.1.5 of the LTR describes the CEG response to PSAI-5 concerning the LGS SAT. This is captured as a Regulatory Commitment in Attachment 10.

8. <u>Limerick Generating Station TS SR Elimination</u>

By Safety Evaluation dated November 9, 2020, the NRC approved WEC topical report WCAP-18461-P-A, "Common Q™ Platform and Component Interface Module System Elimination of Technical Specification Surveillance Requirements," Revision 1 (ADAMS Accession No. ML20230A008). The WCAP-18461-P-A analysis describes the necessary justification for the elimination of certain TS SRs. These SR eliminations take full advantage of the Common Q™ platform self-diagnostic features.

LTR Appendix A, "Elimination of Specific PPS Technical Specification Surveillance Requirements," provides the necessary analyses to justify the elimination of specific TS SRs related to the PPS. These LGS-specific analyses are based on the WCAP-18461-P-A analysis, and the Common Q™ platform. Appendix A also includes the Failure Modes, Effects, Diagnostics Analysis (FMEDA) to support TS SR elimination.

WCAP-18461-P-A lists eight Licensee Required Actions (LRAs) that are required to be addressed when applying the topical report. LTR Section A.8 provides dispositions for each LRA as it applies to the LGS PPS. WCAP-18461-P-A, LRA-8 requires a licensee to include a description of plant administrative controls that will provide assurance that faults are captured and investigated. LTR Appendix A, Item A.8.8 describes the plant administrative controls that will be in place to assure that the PPS self-diagnostics are being captured. These administrative controls may include items such as operator rounds, and system engineer monthly reports that evaluate and document the health, errors, and faults of the safety system.

9. <u>Automated Operator Aids</u>

Section 9.8 of the Reference 16 LTR describes a new feature of the Digital Modernization Project that will automate certain operator controls that were previously performed manually by the operator from the MCR (i.e., Automated Operator Aids (AOAs)). The automated controls described in the LTR will be performed by the non-safety Ovation digital control system, and will assist the MCR operators in the control of RPV level or pressure, testing, and confirmation that the plant is configured and ready for safety functions in the PPS. Automating these controls for specific surveillances and system readiness will reduce the exposure to human error.

However, there are also several Automated Operator Aids performed by the PPS for the HPCI and RCIC systems:

- Transfer to Full Flow Test Mode

  When operating in the RPV injection mode, it is possible to transfer to the Full Flow Test Mode by opening the test return valve and closing the RPV injection valve. This mode is initiated by the operator when RPV injection is not required and places the system into a standby readiness condition operating in the full flow test mode.

- Full Flow Test Mode, including:
  - Auto Pressure Control Mode
  - Transfer to Injection Mode

  Normally, the Full Flow Test Mode is initiated for surveillance testing to demonstrate that a pump can deliver the required flow at a specified pressure. While operating in this mode, the automatic pressure controller can be switched into operation to automatically vary the flow demand for the flow controller which will control turbine speed to achieve the pressure setpoint entered by the operator. The Transfer to Injection Mode aligns the valves for injecting into the RPV, if initiated by the operator while operating in the Full Flow Test Mode.

- Injection Mode including:
  - Auto Level Control Mode
  - Split-Flow Mode

  The Injection Mode is the safety RPV makeup function, initiated automatically or manually. While operating in this mode, the automatic level controller can be switched into operation to automatically vary the flow demand for the flow controller which will control turbine speed to achieve the level setpoint entered by the operator. The Split-Flow Mode, when initiated by the operator, will keep the system running at rated flow under automatic level control, with the test return valve throttled to keep flow near rated. The throttling of the test return valve will be performed by manual operator action.

The Human System Interface for AOAs are accessed from the Division 2 Safety Displays (HPCI) and Division 1 Safety Displays (RCIC).

4.0 REGULATORY EVALUATION

1. Applicable Regulatory Requirements/Criteria

The following regulations and guidance are applicable to the proposed license amendments in support of the Limerick Generating Station Unit 1 and Unit 2 (LGS) Modernization Project installation:

- 10 CFR 50.36, "Technical Specifications." The criteria for limiting conditions for operation and surveillance requirements are in 50.36(c)(2) and (3), respectively.
- The following Criteria in 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants:"
  - Criterion III, "Design Control"
  - Criterion V, "Instructions, Procedures, and Drawings"
  - Criterion VII, "Control of Purchased Material, Equipment, and Services"
  - Criterion XVI, "Corrective Action"

- Paragraph 10 CFR 50.54(jj), "Conditions of Licenses," states that structures, systems, and components subject to the codes and standards of 10 CFR 50.55a must be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety function to be performed.
- Paragraph 10 CFR 50.55a(h), "Protection and safety systems," approves the 1991 version of IEEE Standard 603, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations," for incorporation by reference including the correction sheet dated January 30, 1995. WCAP-18598-P, "PPS Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project," (LTR) provided in Reference 16 includes an IEEE Standard 603 compliance matrix.
- Paragraph 10 CFR 50.55(i), "Conditions of construction permits, early site permits, combined licenses, and manufacturing licenses," states that structures, systems, and components subject to the codes and standards of 10 CFR 50.55a must be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety function to be performed.
- Paragraph 10 CFR 50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants," states that each boiling water reactor must have an alternate rod injection system, a standby liquid control system, and equipment to automatically trip the reactor coolant recirculating pumps under conditions indicative of an ATWS.
- The following General Design Criteria (GDC) in Appendix A to 10 CFR Part 50 are addressed in the Licensing Technical Report (Reference 16):
    - GDC 1, "Quality Standards and Records"
    - GDC 13, "Instrumentation and control"
    - GDC 21, "Protection system reliability and testability"
    - GDC 22, "Protective system independence"
    - GDC 23, "Protection system failure modes"
    - GDC 24, "Separation of protection and control systems"
    - GDC 29, "Protection against anticipated operational occurrences"
- 10 CFR 50, Appendix A, GDC 10 requires that specified acceptable fuel design limits (SAFDLs) are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). The reactor core safety limits are established to preclude violation of these criteria. Automatic enforcement of the reactor core safety limits is provided by the reactor protection system (RPS), which includes a number of reactor trip functions. The reactor trips protect against violating core safety limits during AOOs. In meeting GDC 10, the replacement LGS Plant Protection System (PPS) will continue to satisfy these functional requirements.

- 10 CFR 50, Appendix A, GDC 20 requires that protection system functions shall be designed (1) to automatically initiate the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety. The LGS PPS is designed to meet this GDC requirement. The LGS design basis functions of the RPS, ECCS, NSSSS, RCIC, and EOC-RPT are unchanged following implementation of the LGS PPS.
- 10 CFR 50, Appendix A, GDC 25 provides protection system requirements for reactivity control malfunctions. It states that the protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods. The LGS design basis functions of the RPS are unchanged following implementation of the LGS PPS.
- Regulatory Guide 1.53, Revision 2, "Application of the Single-Failure Criterion to Safety Systems," November 2003 (ADAMS Accession No. ML033220006).
- Regulatory Guide 1.75, Revision 3, "Physical Independence of Electric Systems," February 2005 (ADAMS Accession No. ML13350A340).
- Regulatory Guide 1.97, Revision 5, "Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants," April 2019 (ADAMS Accession No. ML18136A762)
- Regulatory Guide 1.89, Revision 1, " Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," June 1984 (ADAMS Accession No. ML003740271).
- Regulatory Guide 1.100, Revision 3, "Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants," September 2009 (ADAMS Accession No. ML091320468).
- Regulatory Guide 1.152, Revision 3, "Criteria for Use of Computers in Safety Systems of Nuclear Power Plants," July 2011 (ADAMS Accession No. ML102870022)
- Regulatory Guide 1.170, Revision 1, "Software Test Documentation for Digital Computer Software Used in Safety Systems of Nuclear Power Plants," July 2013 (ADAMS Accession No. ML13003A216)
- Regulatory Guide 1.172, Revision 1 "Software Requirements Specifications for Digital Computer Software and Complex Electronics Used in Safety Systems of Nuclear Power Plants," July 2013 (ADAMS Accession No. ML13007A173)
- Regulatory Guide 1.180, Revision 1, "Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems," October 2003 (ADAMS Accession No. ML032740277)
- Regulatory Guide 1.209, "Guidelines for Environmental Qualification of Safety-Related Computer-Based Instrumentation and Control Systems in Nuclear Power Plants," March 2007 (ADAMS Accession No. ML070190294)

- NUREG-0700, "Human-System Interface Design Review Guidelines," Revision 3, July 2020 (ADAMS Accession No. ML ML20162A214)
- NUREG-0711, Revision 3, "Human Factors Engineering Program Review Model," November 2012 (ADAMS Accession No. ML12324A013).
- NUREG-1764, Revision 1, "Guidance for the Review of Changes to Human Actions," September 2007 (ADAMS Accession No. ML072640413)
- NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition" (SRP), Chapter 18, "Human Factors Engineering"
- DI&C-ISG-04, Revision 1, "Task Working Group #4: Highly-Integrated Control Rooms - Communications Issues (HICRc)," March 2007 (ADAMS Accession No. ML083310185)
- DI&C-ISG-06, "Task Working Group #6: Licensing Process," Revision 2, dated December 2018 (ADAMS Accession No. ML18269A259)
- The applicable portions of the following branch technical positions within NUREG-0800, SRP, Chapter 7, "Instrumentation and Controls," as follows:
  - o Branch Technical Position (BTP) 7-14, "Guidance on Software Reviews for Digital Computer- Based Instrumentation and Control Systems"
  - o BTP 7-17, "Guidance on Self-Test and Surveillance Test Provisions"
  - o BTP 7-19, "Guidance for Evaluation of Diversity and Defense-In- Depth in Digital Computer-Based Instrumentation and Control Systems"
  - o BTP 7-21, "Guidance on Digital Computer Real-Time Performance"

The Licensing Technical Report (Reference 16) and the additional attachments to this document contain project-specific compliance information for the above regulations and guidance.

2. Precedent

Alternate Review Process

In Reference 1, Constellation Energy Generation, LLC (CEG) submitted a letter-of-intent (LOI) to the U.S. Nuclear Regulatory Commission (NRC) that described a planned digital license amendment request (LAR) for Limerick Generating Station (LGS), Units 1 and 2. In the LOI, CEG indicated that the LAR would be developed and submitted in accordance with the Alternate Review Process (ARP) guidance in NRC Digital Instrumentation and Control (DI&C) Interim Staff Guidance (ISG)-06, "Licensing Process," Revision 2. CEG has developed this LAR in accordance with the ARP guidance in DI&C ISG-06, Revision 2.

By letter dated July 23, 2020, as supplemented, Entergy Operations, Inc. (Entergy) submitted a license amendment request for Waterford Steam Electric Plant, Unit 3 (Waterford) to implement a planned digital modification (ADAMS Accession No.

ML20205L588). Entergy submitted this LAR in accordance with the DI&C ISG-06, Revision 2 ARP guidance. The NRC approved the license amendment by letter and Safety Evaluation (SE) dated August 24, 2021 (ADAMS Accession No. ML21131A243).

Common Q™ Implementation
Surveillance Requirement Elimination

NRC approval for implementation of the WEC Common Q™ platform, as well as the use of the methodology to eliminate TS SRs that is described in WCAP-18598-P, "PPS Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project," Appendix A, "Elimination of Specific PPS Technical Specification Surveillance Requirements," (Reference 16) is consistent with two precedent licensing actions.

- By letter dated March 25, 2019, as supplemented, Southern Nuclear Company (SNC) submitted a license amendment request for Vogtle Electric Generation Plant (VEGP) Units 3 and 4 (VEGP 3 and 4) to eliminate from TS certain manual surveillance requirements (SRs) required to be performed on Protection and Safety Monitoring System (PMS) components based, in part, on the self-diagnostic functions of the WEC Common Q™ platform (ADAMS Accession No. ML19084A309). The NRC approved the license amendment in an SE (ADAMS Accession No. ML19297D159). In the SE, the NRC determined that the PMS self-diagnostic functions may be credited to provide reasonable assurance that PMS-related LCOs are met, without reliance on performance of the manual SRs on PMS components. This determination was based on the NRC's finding that the PMS self-diagnostic functions (1) are more effective and timelier than these manual SRs at detecting PMS equipment faults, (2) satisfy all QA regulatory requirements for their development, testing, installation, maintenance, and operation, and (3) satisfy regulatory requirements for human factor considerations. In addition, the NRC concluded that reliance on the PMS self-diagnostic functions to provide assurance of meeting the applicable PMS-related LCOs is acceptable under 10 CFR 50.36(c)(2).

- By letter dated July 23, 2020, as supplemented, Entergy submitted a license amendment request for Waterford to implement a planned digital modification at Waterford (ADAMS Accession No. ML20205L588). This LAR included the proposed elimination of certain manual TS SRs based, in part, on the self-diagnostic functions of the WEC Common Qualified (Common Q™) platform, and the VEGP precedent described above. The NRC approved the license amendment by letter and SE dated August 24, 2021 (ADAMS Accession No. ML21131A243). In the SE, the NRC determined that the Common Q™ platform and application-specific self-diagnostic functions provide an adequate means of providing continuous confirmation of system operability. Therefore, the licensee can credit Common Q™ self-diagnostics functions as an acceptable alternative to performing periodic SRs. The NRC also determined that automatic functions that monitor performance of self-diagnostic features, and administrative actions to ensure that self-diagnostic functions are operating, meet the criteria of NRC Branch Technical Position (BTP) 7-17 for checking and monitoring the CPCS self-diagnostic functions during operation.

- Therefore, the NRC determined that the proposed changes met Clauses 5.5, 5.7, and 6.5 of IEEE Std 603-1991, and that the associated guidance of IEEE Std 7-4.3.2-2003 was met.

Component Interface Module (CIM) Diversity

By letter dated March 14, 2007 (ADAMS Accession No. ML070800193), as supplemented, Wolf Creek Nuclear Operating Corporation submitted a license amendment request for the Wolf Creek Generating Station (WCGS) to revise the licensing basis for the Main Steam and Feedwater Isolation System (MSFIS) controls to incorporate field programmable gate array (FPGA) technology as part of the WEC Advanced Logic System (ALS). The NRC approved the license amendment by letter and SE dated March 31, 2009 (ADAMS Accession No. ML19297D159).

The fundamental building block for the LGS CIM is an FPGA integrated circuit. The LGS CIM and the WCGS MSFIS ALS use the same FPGA device. The internal architecture of the FPGA contains design features to address CCF. The development of the LGS CIM used the same processes and implemented the same architectural features that were used to develop the MSFIS design.

Diversity is built into the architecture of the FPGA design and is validated in every step of the FPGA design process. The NRC SE for the WCGS license amendment included a review of the ALS platform, and this review included a conclusion that the features of the ALS platform adequately address common cause failure (CCF) for the MSFIS application.

Elimination of Automatic Isolation Function for TE – MSL Tunnel Temperature – High

The elimination of the Turbine Enclosure (TE) Main Steam Line (MSL) Tunnel Temperature - High automatic isolation function is similar to an NRC approved license amendment for Edwin I. Hatch Nuclear Plant, Unit Nos. 1 and 2 (ADAMS Accession No. ML21286A595). A detailed description of this precedent is included in the Attachment 2 Discussion of Changes for TS 3.7.9.

3. No Significant Hazards Consideration Analysis

In accordance with 10 CFR 50.90, Constellation Energy Generation, LLC (CEG) requests amendments to Renewed Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively. The proposed changes will revise the LGS Updated Final Safety Analysis Report (UFSAR) to incorporate a planned digital modification at LGS (i.e., the LGS Digital Modernization Project). Incorporation of the modification will also result in changes to the LGS Technical Specifications (TS) (i.e., Appendix A to of Renewed Facility Operating License Nos. NPF-39 and NPF-85).

The LGS Digital Modernization Project will replace the existing analog control logic hardware of the Reactor Protection System (RPS) instrumentation, the Nuclear Steam Supply Shutoff System (NSSSS) instrumentation, the Emergency Core Cooling System (ECCS) instrumentation, the Reactor Core Isolation Cooling (RCIC) System instrumentation, and the End-of-Cycle Recirculation Pump Trip (EOC-RPT) instrumentation with a new single digital control system. The new single digital control system (i.e., for RPS, NSSSS, ECCS, RCIC, and EOC-RPT) will be named the Plant Protection System (PPS).

The following current TS sections are affected by the proposed changes to incorporate the new single digital control system. In addition to the TS changes associated with the new digital control system, the proposed changes will revise LGS TS 3.3.2.1, "Primary Containment Isolation Instrumentation," Table 3.3.2.1-1, to eliminate automatic main steam line isolation on high turbine building area temperature (i.e., Function 1.g). In lieu of automatic isolation, a new specification, TS 3/4.7.9, "Turbine Enclosure (TE) Main Steam Line (MSL) Tunnel Temperature," is proposed that requires monitoring the MSL tunnel temperature and a plant shut down if main steam line leakage is detected.

- 1.0 Definitions
- 2.2.1 Limiting Safety System Settings
- 3/4.3.1 Reactor Protection System Instrumentation
- 3/4.3.2 Isolation Actuation Instrumentation
- 3/4.3.3 Emergency Core Cooling System Actuation Instrumentation
- 3/4.3.3.A Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation
- 3/4.3.4.1 Anticipated Transient Without Scram·Recirculation Pump Trip (ATWS-RPT) System Instrumentation
- 3/4.3.4.2 End-of-Cycle Recirculation Pump Trip (EOC-RPT) System Instrumentation
- 3/4.3.5 Reactor Core Isolation Cooling System Actuation Instrumentation
- 3/4.4.3.2 Operational Leakage
- 3/4.5.1 ECCS – Operating
- 3/4.7.3 Reactor Core Isolation Cooling System
- 3/4.7.9 Turbine Enclosure (TE) Main Steam Line (MSL) Tunnel Temperature
- 3/4.10.8 Inservice Leak and Hydrostatic Testing
- 6.9.1.9 Core Operating Limits Report

In addition to the changes to affected TS, the proposed change reclassifies the Redundant Reactivity Control System (RRCS) to non-safety-related, consistent with the system classification requirements of 10 CFR 50.62, and eliminates the automatic RRCS feedwater runback (FWRB) function as part of the PPS modification, while retaining the manual FW pump trip function. These two additional proposed changes do not impact the LGS TS.

As described above, based on the potential for ambient temperature swings in the Turbine Enclosure (TE) for reasons other than actual main steam leaks, which could potentially result in exceeding the TE Main Steam Line (MSL) tunnel area temperature setpoint and causing an unnecessary Group I isolation and subsequent reactor scram, CEG has elected to include elimination of the automatic isolation function for TE - MSL Tunnel Temperature – High in the modification and the addition of TS-required manual actions. CEG has evaluated whether a significant hazards consideration is involved with the proposed amendment by focusing on the three conditions set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed changes do not alter any of the previously evaluated accidents in the UFSAR. The proposed changes do not affect any of the initiators of previously evaluated accidents in a manner that would increase the likelihood of the event. The proposed changes will reduce the potential for human error, increase the speed and accuracy of operational decision-making, increase full system availability and reliability, and enhance self-diagnostic capabilities. As a result, the likelihood of malfunction of an SSC is not increased. The proposed changes affect the instrumentation systems that initiate mitigation systems. The reliability of the new instrumentation systems is as good as or better than the existing systems. The capability and operation of the mitigation systems are not affected by the proposed changes. Thus, the mitigating systems will continue to be initiated and mitigate the consequences of an accident as assumed in the analysis of accidents previously evaluated.

   The proposed change to reclassify RRCS from safety-related to non-safety-related, consistent with the system classification requirements of 10 CFR 50.62, does not affect any accident initiators of previously evaluated accidents in a manner that would increase the likelihood of the event. Similarly, reclassification, consistent with 10 CFR 50.62 requirements, does not affect the capability and operation of the system. Thus, the RRCS will continue to be initiated and mitigate the consequences of an accident as assumed in the analysis of accidents previously evaluated.

   The proposed change to eliminate the automatic RRCS FWRB function does not affect any accident initiators of previously evaluated accidents in a manner that would increase the likelihood of the event. In addition, a supporting evaluation concludes that the ATWS acceptance criteria for maintaining reactor vessel integrity, containment integrity, and a coolable core geometry will continue to be met with elimination of the automatic RRCS FWRB function. As such, the current LGS ATWS analysis conclusions will remain valid with the elimination.

   The proposed change also eliminates the automatic MSIV isolation function associated with TE MSL Tunnel high temperature from the requirements of the Technical Specifications (TS) and creates TS requirements for TE MSL tunnel temperature monitoring in a new TS 3/4.7.9.

   Automatic isolation of the MSIVs on TE MSL tunnel high temperature is not an initiator of any accident previously evaluated. A manual plant shutdown initiated due to MSL leakage in the TE MSL tunnel is not an initiator of any accident previously evaluated.

   There is no credit taken in any licensing basis analysis for main steam isolation valve (MSIV) closure on TE MSL tunnel high temperature, and there are no calculations that credit the subject isolation function as a mitigative feature.

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

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

   Response: No.

   The functional design of the RPS, NSSSS instrumentation, ECCS instrumentation, RCIC system instrumentation, and EOC-RPT system instrumentation and their design basis functions are not altered by the proposed changes. The operation of the new equipment is not substantially different than the existing equipment and human factors studies have determined that the risk of human error is not increased. The components installed as part of the proposed changes will be supplied to equivalent or better. Some existing manual tests are replaced with automatic testing, reducing the risk of test-initiated events.

   The proposed changes will not introduce any new operating modes, safety-related equipment lineups, accident scenarios, system interactions, or failure modes that would create a new or different type of accident. Failure(s) of the system will have the same overall effect as the present design.

   The proposed change to reclassify RRCS from safety-related to non-safety-related, consistent with the system classification requirements of 10 CFR 50.62 will not introduce any new operating modes, safety-related equipment lineups, accident scenarios, system interactions, or failure modes that would create a new or different type of accident. Failure(s) of the system will have the same overall effect as the present design.
   The proposed change to eliminate the automatic RRCS FWRB function will not introduce any new operating modes, safety-related equipment lineups, accident scenarios, system interactions, or failure modes that would create a new or different type of accident. Failure(s) of the system will have the same overall effect as the present design.

   The proposed change also eliminates the automatic MSIV isolation function associated with TE MSL Tunnel high temperature from the requirements of the TS and creates TS requirements for TE MSL tunnel temperature monitoring in a new TS 3/4.7.9.

   Eliminating the automatic isolation of the MSIVs will not create a new or different kind of accident from those previously evaluated as a Main Steam Line Break has been evaluated. Elimination of the automatic isolation function will not create a new failure mechanism as a plant shutdown continues to be required if an MSL leak is detected. The proposed change from an automatic shutdown to a manual shutdown will not create any credible new failure mechanisms, malfunctions, or accident initiators not considered in the design and licensing bases. The unlikely failure to manually detect an MSL leak and shutdown the plant and that failure leading to a Main Steam Line Break has already been evaluated and is not a new type of accident.

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

3. Does the proposed amendment involve a significant reduction in a margin of safety?

   Response: No.

   The proposed changes do not affect the accident source term, containment isolation, or radiological release assumptions used in evaluating the radiological consequences of any accident previously evaluated and are consistent with safety analysis assumptions and resultant consequences. The proposed changes do not impact reactor operating parameters or the functional requirements of the affected instrumentation systems. These systems will continue to provide the design basis reactor trips and protective system actuations. All design basis events, and the reliance on the reactor trips and protective system actuations will remain unchanged. No controlling numerical values for parameters established in the UFSAR or the license or Safety Limits are affected by the proposed changes.

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

Based on the above, CEG concludes that the proposed amendments do not involve a 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.

4. <u>Conclusions</u>

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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL CONSIDERATION

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 Part 20, and 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.

6.0 REFERENCES

1. Exelon Generation Company, LLC letter to the U.S. Nuclear Regulatory Commission (NRC), "Letter-of-Intent to Submit a License Amendment Request for the Limerick Digital Modernization Project," (ADAMS Accession No. ML20346A026), dated December 11, 2020
2. NRC Digital Instrumentation and Control (DI&C) Interim Staff Guidance (ISG)-06, "Licensing Process," Revision 2
3. NRC Meeting Summary, "Summary of June 12, 2020, Public Telephone Conference with Exelon Generation Company, LLC Regarding Planned Digital Modernization License Amendment Request for Limerick Generating Station, Units 1 and 2 (EPID L-2020-LRM-0041)," (ADAMS Accession No. ML20175A240), dated June 30, 2020
4. NRC Meeting Summary, "Summary of March 16, 2021, Public Meeting with Exelon Generation Company, LLC Regarding Planned Digital Modernization License Amendment Request for Limerick Generating Station, Units 1 and 2 (EPID L-2020-LRM-0041) (ADAMS Accession No. ML21123A136), dated May 13, 2021
5. NRC Meeting Summary, "Summary of June 29, 2021, Public Meeting with Exelon Generation Company, LLC Regarding Planned Digital Modernization License Amendment Request for Limerick Generating Station, Units 1 and 2 (EPID L-2020-LRM-0041) (ADAMS Accession No. ML21301A161), dated November 15, 2021
6. NRC Meeting Summary, "Summary of October 20, 2021, Presubmittal Public Meeting with Exelon Generation Company, LLC Regarding Planned Digital Modernization License Amendment Request for Limerick Generating Station, Units 1 and 2 (EPID L-2020-LRM-0041) (ADAMS Accession No. ML21300A277), dated November 9, 2021
7. NRC Meeting Summary, "Summary of December 7, 2021, Public Meeting with Exelon Generation Company, LLC Regarding Planned Digital Modernization License Amendment Request for Limerick Generating Station, Units 1 and 2 (EPID L-2020-LRM-0041) (ADAMS Accession No. ML22021B294), dated February 2, 2022
8. NRC Meeting Summary, "Summary of January 11, 2022, Public Meeting with Exelon Generation Company, LLC Regarding Planned Digital Modernization License Amendment Request for Limerick Generating Station, Units 1 and 2 (EPID L-2020-LRM-0041) (ADAMS Accession No. ML22038A099), dated February 23, 2022
9. NRC Meeting Notice, "Pre-Submittal Meeting with Constellation Energy Generation, LLC Regarding Planned Digital Modernization License Amendment Request for Limerick Generating Station, Units1 and 2," (ADAMS Accession No. ML22090A013), dated February 25, 2022 (March 31, 2022 Meeting Date)
10. NRC Meeting Notice, "Meeting Between NRC Staff and Constellation Energy Generation, LLC Regarding Review of Limerick Generating Station, Units 1 and 2 Defense-in-Depth and Diversity Coping Analysis Associated with Digital Upgrade of Protection System," (ADAMS Accession No. ML22129A142), dated May 9, 2022 (May 18, 2022 Meeting Date)

11. NRC Meeting Notice, "Presubmittal Meeting with Constellation Energy Generation, LLC About Planned Digital Modernization License Amendment Request for Limerick Generating Station, Units 1 and 2," (ADAMS Accession No. ML22145A213), dated May 25, 2022 (June 9, 2022 Meeting Date)

12. NRC Meeting Notice, "Meeting Between NRC Staff and Constellation Energy Generation, LLC on the Review of the Defense-in-Depth and Diversity Coping Analysis Supporting the Digital Upgrade of Instrumentation and Controls at Limerick Generating Station, Units 1 and 2," (ADAMS Accession No. ML22154A133), dated June 3, 2022 (June 16, 2022 Meeting Date)

13. NRC Meeting Notice, "Meeting Between NRC Staff and Constellation Energy Generation, LLC on the Review of the Defense-in-Depth and Diversity Coping Analysis Supporting the Digital Upgrade of Instrumentation and Controls at Limerick Generating Station, Units 1 and 2," (ADAMS Accession No. ML22203A084), dated July 8, 2022 (July 22, 2022 Meeting Date)

14. NRC Meeting Notice, "Presubmittal Meeting with Constellation Energy Generation, LLC About Planned Digital Modernization License Amendment Request for Limerick Generating Station, Units 1 and 2," (ADAMS Accession No. ML22250A475), dated August 25, 2022 (September 8, 2022 Meeting Date)

15. Westinghouse Electric Company LLC, WCAP-16097-P-A, Revision 5, "Common Qualified Platform Topical Report," (ADAMS Accession No. ML21140A104), dated May 2021

16. Westinghouse Electric Company LLC, WCAP-16096-P-A, Revision 5.1, "Software Program Manual for Common Q™ Systems," (ADAMS Accession No. ML21146A203), dated May 2021

17. Constellation Energy Generation, LLC (CEG) letter to the NRC, "Review of Limerick Generating Station Defense in Depth and Diversity Common Cause Failure Coping Analysis, WNA-AR-01074-GLIM-P, Revision 1, February 2022," (ADAMS Accession No. ML22045A480), dated February 14, 2022

18. CEG letter to the NRC, "Review of Limerick Generating Station Defense in Depth and Diversity Common Cause Failure Coping Analysis, WNA-AR-01074-GLIM-P, Revision 2, July 2022, and the Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project, WCAP-18598-P, Revision 0, July 2022," dated August 12, 2022 (ADAMS Accession No. ML22224A146)

19. Westinghouse Electric Company LLC letter to the NRC, "Submittal of WNA-AR-01054-GEN-P, 'Component Interface Module (CIM) Diversity Analysis, Revision 0' (proprietary)," (ADAMS Accession Nos. ML22231A179 and ML22231A180), dated August 19, 2022

Attachment 2

License Amendment Request

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

Description of Proposed Technical Specifications

Introduction

Proposed Technical Specifications Changes

The proposed Technical Specifications (TS) changes to the Limerick Generating Station (LGS) Unit 1 and Unit 2 TS are described in this attachment. The discussion of proposed TS changes is divided, as appropriate, by TS Chapter, Specification, or group of Specifications. The sections are:

- Chapter 1, Definitions
- Section 2.2.1, Limiting Safety System Settings
- Specification 3.3.1, Plant Protection System Instrumentation Channels
- Specification 3.3.2, Plant Protection System Divisions
- Specification 3.3.3, Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation
- Specification 3.3.4.1, ATWS Recirculation Pump Trip System Instrumentation
- Specification 3.3.4.2, End of Cycle (EOC) Recirculation Pump Trip System Instrumentation
- Specification 3.3.5, Loss of Power Instrumentation
- Specification 3/4.5, ECCS – Operating
- Specification 3/4.7.9, Turbine Enclosure - Main Steam Line Tunnel Temperature
- Various Additional Specifications
  - 3/4.4.3.2, Operational Leakage
  - 3/4.7.3, Reactor Core Isolation Cooling System
  - 3/4.10.8, Inservice Leak and Hydrostatic Testing
  - 6.9.1.9, Core Operating Limits Report

Each section contains the following:

- LGS Unit 1 Current TS (CTS) Markup
- LGS Unit 2 CTS Markup
- Discussions of Change justifying the changes to the CTS
- LGS Unit 1 Proposed TS (PTS) Clean Copy
- LGS Unit 2 PTS Clean Copy
- LGS Unit 1 TS Bases Markup, provided for information only[1].
- LGS Unit 2 TS Bases Markup, provided for information only.

[1] TS Bases markups are not provided for TS Chapter 1, "Definitions" or TS 6.9.1.9 since there are no Bases for these sections.

The CTS TS markup pages contain references on the right-hand side of each page to the Discussion of Change (DOC) that justifies the indicated change (e.g., D01, D02, etc.). In the CTS markup, removed text is struck-through and added text is enclosed in a square box. The box is joined to the location for the new text with an arrow if the location is not clear.

The CTS TS markup pages contain cross references on the left-hand side of each page to indicate the new location of the requirement in the PTS. CTS portions dispositioned in another specification are enclosed in a square box and the dispositioning specification is provided in the left-hand column. If a CTS page is incorporated into multiple PTS, the CTS page is repeated in the CTS markup for each PTS. As an editorial improvement, items marked "Deleted" in the current TS and pages marked as "Intentionally Blank" are not included in the proposed TS.

The Unit 1 PTS clean copy TS pages contain cross references on the left-hand side of each page to indicate the CTS source for specific requirements. The cross references are omitted on the Unit 2 PTS clean copy TS pages for clarity.

The PTS clean copy for each section is technically correct but not publication ready. The PTS wording reflects the proposed TS. However, aspects of the presentation, such as page numbers, page breaks, and line breaks, may be different in the publication-ready pages to be provided to the NRC for inclusion in the issued amendment.

The LGS TS Bases changes are provided for information only. The regulation at 10 CFR 50.36(a)(1) requires a summary statement of the bases or reasons for specifications, other than those covering administrative controls. The proposed TS Bases changes that reflect the proposed TS changes and are consistent with the format and level of detail of the existing LGS Bases, are provided for information, consistent with the intent of 10 CFR 50.36(a)(1). Approval of the TS Bases changes is not requested. The TS Bases changes will be processed in accordance with LGS TS 6.8.4.h, "Technical Specifications (TS) Bases Control Program."

Chapter 1, Definitions

Unit 1

Current Technical Specifications Markup

DRAIN TIME (Continued)

susceptible to a common mode failure, for all penetration flow paths below the TAF except:

1. Penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are closed and administratively controlled in the closed position, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths;

2. Penetration flow paths capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation; or

3. Penetration flow paths with isolation devices that can be closed prior to the RPV water level being equal to the TAF by a dedicated operator trained in the task, who is in continuous communication with the control room, is stationed at the controls, and is capable of closing the penetration flow path isolation device without offsite power.

c) The penetration flow paths required to be evaluated per paragraph b) are assumed to open instantaneously and are not subsequently isolated, and no water is assumed to be subsequently added to the RPV water inventory;

d) No additional draining events occur; and

e) Realistic cross-sectional areas and drain rates are used.

A bounding DRAIN TIME may be used in lieu of a calculated value.

1.10 (Deleted)

~~EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME~~

~~1.11 The EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ECCS actuation set-point at the channel sensor until the ECCS equipment is capable of performing its safety function, i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.~~

D01

1.11 (Deleted)

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

1.12 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker from initial movement of the associated:

a. Turbine stop valves, and
b. Turbine control valves.

This total system response time consists of two components, the instrumentation response time and the breaker arc suppression time. These times may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

1.13 (Deleted)
1.14 (Deleted)

FREQUENCY NOTATION

1.15 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

HIGH (POWER) TRIP SETPOINT (HTSP)

1.15a The high power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable above 85% reactor thermal power.

IDENTIFIED LEAKAGE

1.16 IDENTIFIED LEAKAGE shall be:

a. Leakage into collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of the leakage detection systems or not to be PRESSURE BOUNDARY LEAKAGE.

INSERVICE TESTING PROGRAM

1.16a The INSERVICE TESTING PROGRAM is the licensee program that fulfills the requirements of 10 CFR 50.55a(f).

INTERMEDIATE (POWER) TRIP SETPOINT (ITSP)

1.16b The intermediate power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable between 65% and 85% reactor thermal power.

1.17 (Deleted)

~~ISOLATION SYSTEM RESPONSE TIME~~

~~1.17 The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation actuation setpoint at the channel sensor until the isolation valves travel to their required positions. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.~~

D01

LIMITING CONTROL ROD PATTERN

1.18 A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, OR MCPR.

LINEAR HEAT GENERATION RATE

1.19 LINEAR HEAT GENERATION RATE (LHGR) shall be the heat generation per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.

Insert 1.1

D01

OPERATIONAL CONDITION - CONDITION

1.26 An OPERATIONAL CONDITION, i.e., CONDITION, shall be any one inclusive combination of mode switch position and average reactor coolant temperature as specified in Table 1.2.

PHYSICS TESTS

1.27 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PRESSURE BOUNDARY LEAKAGE

1.28 PRESSURE BOUNDARY LEAKAGE shall be leakage through a nonisolable fault in a reactor coolant system component body, pipe wall or vessel wall.

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

1.28a The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current vessel fluence period. The pressure and temperature limits shall be determined for each fluence period in accordance with Specification 6.9.1.13.

PRIMARY CONTAINMENT INTEGRITY

1.29 PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All primary containment penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE primary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except for valves that are opened under administrative control as permitted by Specification 3.6.3.

b. All primary containment equipment hatches are closed and sealed.

c. The primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. The primary containment leakage rates are within the limits of Specification 3.6.1.2.

e. The suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

f. The sealing mechanism associated with each primary containment penetration; e.g., welds, bellows, or O-rings, is OPERABLE.

PROCESS CONTROL PROGRAM

1.30 The PROCESS CONTROL PROGRAM (PCP) shall contain the provisions to assure that the solidification or dewatering and packaging of radioactive wastes results in a waste package with properties that meet the minimum and stability requirements of 10 CFR Part 61 and other requirements for transportation to the disposal site and receipt at the disposal site. With solidification or dewatering, the PCP shall identify the process parameters influencing solidification or dewatering, based on laboratory scale and full scale testing or experience.

TS 1.0
Insert 1.1

PLANT PROTECTION SYSTEM RESPONSE TIME

1.27a PLANT PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component (e.g., de-energization of the scram pilot valve solenoids, the valves travel to their required positions, pump discharge pressures reach their required values, isolation valves travel to their required positions). Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured. In lieu of measurement, a fixed response time may be applied for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

PURGE - PURGING

1.31 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.32 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3515 MWt.

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

1.33 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All reactor enclosure secondary containment penetrations required to be closed during accident conditions are either:

1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, slide gate damper, or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.1.

b. All reactor enclosure secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. The reactor enclosure recirculation system is in compliance with the requirements of Specification 3.6.5.4.

e. At least one door in each access to the reactor enclosure secondary containment is closed except when the access opening is being used for entry and exit.

f. The sealing mechanism associated with each reactor enclosure secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

g. The pressure within the reactor enclosure secondary containment is less than or equal to the value required by Specification 4.6.5.1.1a, except as indicated by the footnote for Specification 4.6.5.1.1a.

1.34 (Deleted)

~~REACTOR PROTECTION SYSTEM RESPONSE TIME~~

~~1.34 REACTOR PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.~~

D01

RECENTLY IRRADIATED FUEL

1.35 RECENTLY IRRADIATED FUEL is fuel that has occupied part of a critical reactor core within the previous 24 hours.

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY

1.36 REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All refueling floor secondary containment penetrations required to be closed during accident conditions are either:

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY (Continued)

1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, slide gate damper, or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.2.

b. All refueling floor secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of specification 3.6.5.3.

d. At least one door in each access to the refueling floor secondary containment is closed except when the access opening is being used for entry and exit.

e. The sealing mechanism associated with each refueling floor secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

f. The pressure within the refueling floor secondary containment is less than or equal to the value required by Specification 4.6.5.1.2a, except as indicated by the footnote for Specification 4.6.5.1.2a.

REPORTABLE EVENT

1.37 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

RESTRICTED AREA

1.37a RESTRICTED AREA means an area, access to which is limited by the licensee for the purpose of protecting individuals against undue risks from exposure to radiation and radioactive materials. RESTRICTED AREA does not include areas used as residential quarters, but separate rooms in a residential building may be set apart as a RESTRICTED AREA.

~~1.38 (Deleted)~~ Insert 1.2

D02

SHUTDOWN MARGIN (SDM)

1.39 SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical throughout the operating cycle assuming that:

a. The reactor is xenon free;

b. The moderator temperature is ≥ 68°F, corresponding to the most reactive state; and

c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

SITE BOUNDARY

1.40 The SITE BOUNDARY shall be that line as defined in Figure 5.1.3-1a.

SOURCE CHECK

1.41 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

TS 1.0
Insert 1.2

SENSOR CHANNEL CALIBRATION

1.38 A SENSOR CHANNEL CALIBRATION shall be the adjustment, as necessary, of the sensor output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. Calibration of nonadjustable sensor channels, such as digital inputs, resistance temperature detectors (RTD) or thermocouples, may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the any remaining adjustable devices in the channel. Neutron detectors may be excluded from SENSOR CHANNEL CALIBRATION. The SENSOR CHANNEL CALIBRATION may be performed by any series of sequential, overlapping, or total channel steps such that the entire sensor channel is calibrated, and each step must be performed within the Frequency in the Surveillance Frequency Control Program for the devices included in the step.

Unit 2

Current Technical Specifications Markup

DEFINITIONS

DRAIN TIME (Continued)

susceptible to a common mode failure, for all penetration flow paths below the TAF except:

1. Penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are closed and administratively controlled in the closed position, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths;

2. Penetration flow paths capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation; or

3. Penetration flow paths with isolation devices that can be closed prior to the RPV water level being equal to the TAF by a dedicated operator trained in the task, who is in continuous communication with the control room, is stationed at the controls, and is capable of closing the penetration flow path isolation device without offsite power.

c) The penetration flow paths required to be evaluated per paragraph b) are assumed to open instantaneously and are not subsequently isolated, and no water is assumed to be subsequently added to the RPV water inventory;

d) No additional draining events occur; and

e) Realistic cross-sectional areas and drain rates are used.

A bounding DRAIN TIME may be used in lieu of a calculated value.

1.10 (Deleted)

~~EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME~~

~~1.11 The EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ECCS actuation set-point at the channel sensor until the ECCS equipment is capable of performing its safety function, i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.~~

D01

1.11 (Deleted)

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

1.12 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker from initial movement of the associated:

a. Turbine stop valves, and
b. Turbine control valves.

This total system response time consists of two components, the instrumentation response time and the breaker arc suppression time. These times may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

1.13 (Deleted)
1.14 (Deleted)

FREQUENCY NOTATION

1.15 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

HIGH (POWER) TRIP SETPOINT (HTSP)

1.15a The high power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable above 85% reactor thermal power.

IDENTIFIED LEAKAGE

1.16 IDENTIFIED LEAKAGE shall be:

a. Leakage into collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known to not interfere with the operation of the leakage detection systems.

INSERVICE TESTING PROGRAM

1.16a The INSERVICE TESTING PROGRAM is the licensee program that fulfills the requirements of 10 CFR 50.55a(f).

INTERMEDIATE (POWER) TRIP SETPOINT (ITSP)

1.16b The intermediate power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable between 65% and 85% reactor thermal power.

1.17 (Deleted)

~~ISOLATION SYSTEM RESPONSE TIME~~

~~1.17 The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation actuation setpoint at the channel sensor until the isolation valves travel to their required positions. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.~~

D01

LIMITING CONTROL ROD PATTERN

1.18 A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, or MCPR.

LINEAR HEAT GENERATION RATE

1.19 LINEAR HEAT GENERATION RATE (LHGR) shall be the heat generation per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.

OPERATIONAL CONDITION - CONDITION
1.26 An OPERATIONAL CONDITION, i.e., CONDITION, shall be any one inclusive combination of mode switch position and average reactor coolant temperature as specified in Table 1.2.

PHYSICS TESTS
1.27 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

Insert 1.1

D01

PRESSURE BOUNDARY LEAKAGE
1.28 PRESSURE BOUNDARY LEAKAGE shall be leakage through a fault in a reactor coolant system component body, pipe wall or vessel wall. Leakage past seals, packing, and gaskets is not PRESSURE BOUNDARY LEAKAGE.

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)
1.28a The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current vessel fluence period. The pressure and temperature limits shall be determined for each fluence period in accordance with Specification 6.9.1.13.

PRIMARY CONTAINMENT INTEGRITY
1.29 PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All primary containment penetrations required to be closed during accident conditions are either:

    1. Capable of being closed by an OPERABLE primary containment automatic isolation system, or

    2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except for valves that are opened under administrative control as permitted by Specification 3.6.3.

b. All primary containment equipment hatches are closed and sealed.

c. The primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. The primary containment leakage rates are within the limits of Specification 3.6.1.2.

e. The suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

f. The sealing mechanism associated with each primary containment penetration; e.g., welds, bellows, or O-rings, is OPERABLE.

PROCESS CONTROL PROGRAM
1.30 The PROCESS CONTROL PROGRAM (PCP) shall contain the provisions to assure that the solidification or dewatering and packaging of radioactive wastes results in a waste package with properties that meet the minimum and stability requirements of 10 CFR Part 61 and other requirements for transportation to the disposal site and receipt at the disposal site. With solidification or dewatering, the PCP shall identify the process parameters influencing solidification or dewatering based on laboratory scale and full scale testing or experience.

TS 1.0
Insert 1.1

PLANT PROTECTION SYSTEM RESPONSE TIME

1.27a PLANT PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component (e.g., de-energization of the scram pilot valve solenoids, the valves travel to their required positions, pump discharge pressures reach their required values, isolation valves travel to their required positions). Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured. In lieu of measurement, a fixed response time may be applied for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

DEFINITIONS

PURGE - PURGING

1.31 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.32 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3515 MWt.

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

1.33 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All reactor enclosure secondary containment penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, slide gate damper or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.1.

b. All reactor enclosure secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. The reactor enclosure recirculation system is in compliance with the requirements of Specification 3.6.5.4.

e. At least one door in each access to the reactor enclosure secondary containment is closed, except when the access opening is being used for entry and exit.

f. The sealing mechanism associated with each reactor enclosure secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

g. The pressure within the reactor enclosure secondary containment is less than or equal to the value required by Specification 4.6.5.1.1a, except as indicated by the footnote for Specification 4.6.5.1.1a.

1.34 (Deleted)

~~REACTOR PROTECTION SYSTEM RESPONSE TIME~~

~~1.34 REACTOR PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.~~

D01

RECENTLY IRRADIATED FUEL

1.35 RECENTLY IRRADIATED FUEL is fuel that has occupied part of a critical reactor core within the previous 24 hours.

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY

1.36 REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All refueling floor secondary containment penetrations required to be closed during accident conditions are either:

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY (Continued)

1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, slide gate damper or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.2.

b. All refueling floor secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. At least one door in each access to the refueling floor secondary containment is closed, except when the access opening is being used for entry and exit.

e. The sealing mechanism associated with each refueling floor secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

f. The pressure within the refueling floor secondary containment is less than or equal to the value required by Specification 4.6.5.1.2a, except as indicated by the footnote for Specification 4.6.5.1.2a.

REPORTABLE EVENT

1.37 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

RESTRICTED AREA

1.37a RESTRICTED AREA means an area, access to which is limited by the licensee for the purpose of protecting individuals against undue risks from exposure to radiation and radioactive materials. RESTRICTED AREA does not include areas used as residential quarters, but separate rooms in a residential building may be set apart as a RESTRICTED AREA.

~~1.38 (Deleted)~~ Insert 1.2 D02

SHUTDOWN MARGIN (SDM)

1.39 SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical throughout the operating cycle assuming that:

a. The reactor is xenon free;

b. The moderator temperature is ≥ 68°F, corresponding to the most reactive state; and

c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

SITE BOUNDARY

1.40 The SITE BOUNDARY shall be that line as defined in Figure 5.1.3-1a.

SOURCE CHECK

1.41 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

TS 1.0
Insert 1.2

SENSOR CHANNEL CALIBRATION

1.38 A SENSOR CHANNEL CALIBRATION shall be the adjustment, as necessary, of the sensor output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. Calibration of nonadjustable sensor channels, such as digital inputs, resistance temperature detectors (RTD) or thermocouples, may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the any remaining adjustable devices in the channel. Neutron detectors may be excluded from SENSOR CHANNEL CALIBRATION. The SENSOR CHANNEL CALIBRATION may be performed by any series of sequential, overlapping, or total channel steps such that the entire sensor channel is calibrated, and each step must be performed within the Frequency in the Surveillance Frequency Control Program for the devices included in the step.

Discussion of Changes

Discussion of Changes

Chapter 1, Definitions

D01

LGS TS Chapter 1 contains definitions for Reactor Protection System (RPS) Response Time (TS 1.34), Isolation System Response Time (TS 1.17), and Emergency Core Cooling System (ECCS) Response Time (TS 1.11). These definitions are used in the corresponding Reactor Protection System, Isolation System, and ECCS specifications, and are very similar. These definitions are deleted and replaced with a new definition of Plant Protection System (PPS) Response Time (proposed TS 1.27a).

The new PPS Response Time definition incorporates all aspects of the existing definitions by measuring the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component (e.g., de-energization of the scram pilot valve solenoids, valves travel to their required positions, pump discharge pressures reach their required values, isolation valves travel to their required positions) and includes diesel generator starting and sequence loading delays, where applicable. Like the current definitions, the PPS Response Time definition permits the response time to be measured by any series of sequential, overlapping or total steps such that the entire response time is measured. A new allowance is added that permits a fixed response time to be used for selected components in lieu of measurement provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

This change is acceptable because the new definition does not impose any new requirements or relax any existing requirements provided by the existing TS. The definitions are simply combined to reflect the new organization of the TS. The new allowance that permits a fixed response time to be used for selected components in lieu of measurement was approved in LGS TS Amendment 132/93, issued on December 14, 1998 (ADAMS Accession No. 981223031).

This amendment eliminated response time measurement for selected sensors and instrument loops and allowed the use of fixed response times. These changes were indicated by notes on the specific response time functions, but the response time testing definitions were not revised to reflect these changes. The proposed change incorporates an allowance into the definition to acknowledge that fixed, allocated response times may be used for some components in lieu of measurement. The wording of the allowance is similar to wording in NUREG-1433, "Standard Technical Specifications General Electric BWR/4 Plants" (NUREG-1433 STS) and reflects current LGS TS provisions that are not recognized in the current definitions. Other changes related to response time testing are discussed in each specification. As the new definition is an administrative combination of the existing definitions and incorporates an already approved allowance, the change is acceptable.

D02

LGS TS Chapter 1 is revised to add a new defined term, Sensor Channel Calibration (proposed TS 1.38). The Sensor Channel Calibration definition is very similar to the existing Channel Calibration definition except that it does not encompass the entire channel including alarm and/or trip functions, and requiring the Channel Functional Test. WCAP-18598-P, "PPS Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project" (PPS Licensing Technical Report) (i.e., Attachment 4 to the LAR), Appendix A explains how the PPS self-diagnostics encompass the existing Channel Functional Test, including alarm and/or trip functions. The definition also incorporates existing allowances, such as exclusion of neutron detectors and other nonadjustable devices, including digital inputs, thermocouples, and resistance temperature detectors. This definition is used in the instrumentation TS in lieu of the existing Channel Calibration definition. The definition retains the existing allowance to perform the calibration by any series of sequential, overlapping, or total channel steps such that the entire sensor channel is calibrated, and that each step must be performed within the Frequency in the Surveillance Frequency Control Program (SFCP) for the devices included in the step.

As described in the PPS Licensing Technical Report, the PPS self-testing capability will ensure that each channel remains calibrated from the input from the sensor to the output to the actuated devices.

The proposed TS 1.38 Sensor Channel Calibration definition provides a description of the required testing of the channel to ensure it responds with the necessary range and accuracy to known values of the parameter which the channel monitors up to the input to the PPS. Section 3.2 of the PPS Licensing Technical Report provides a description of the PPS architecture. The definition acknowledges that some inputs to the PPS are not adjustable, such as digital inputs and certain types of sensors, but the Sensor Channel Calibration must ensure the inputs are behaving as expected. This acknowledgement is consistent with the existing Channel Calibration definition, as well as specific Notes in the LGS TS. Therefore, the Sensor Channel Calibration provides the appropriate testing of the inputs to the PPS. Other surveillance changes are discussed in each specification.

Unit 1

Proposed Technical Specifications

DRAIN TIME (Continued)

susceptible to a common mode failure (e.g., seismic event, loss of normal power, single human error), for all penetration flow paths below the TAF except:

1. Penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are locked, sealed, or otherwise secured in the closed position, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths;

2. Penetration flow paths capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation; or

3. Penetration flow paths with isolation devices that can be closed prior to the RPV water level being equal to the TAF by a dedicated operator trained in the task, who is in continuous communication with the control room, is stationed at the controls, and is capable of closing the penetration flow path isolation device without offsite power.

c) The penetration flow paths required to be evaluated per paragraph b) are assumed to open instantaneously and are not subsequently isolated, and no water is assumed to be subsequently added to the RPV water inventory;

d) No additional draining events occur; and

e) Realistic cross-sectional areas and drain rates are used.

A bounding DRAIN TIME may be used in lieu of a calculated value.

1.10 (Deleted)

1.11 (Deleted)

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

1.12 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker from initial movement of the associated:

a. Turbine stop valves, and
b. Turbine control valves.

This total system response time consists of two components, the instrumentation response time and the breaker arc suppression time. These times may be measured by any series of sequential, overlapping, or total steps such that the entire response time is measured.

1.13 (Deleted)
1.14 (Deleted)

FREQUENCY NOTATION

1.15 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

HIGH (POWER) TRIP SETPOINT (HTSP)

1.15a The high power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable above 85% reactor thermal power.

IDENTIFIED LEAKAGE

1.16 IDENTIFIED LEAKAGE shall be:

a. Leakage into collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of the leakage detection systems or not to be PRESSURE BOUNDARY LEAKAGE.

INSERVICE TESTING PROGRAM

1.16a The INSERVICE TESTING PROGRAM is the licensee program that fulfills the requirements of 10 CFR 50.55a(f).

INTERMEDIATE (POWER) TRIP SETPOINT (ITSP)

1.16b The intermediate power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable between 65% and 85% reactor thermal power.

1.17 (Deleted)

LIMITING CONTROL ROD PATTERN

1.18 A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, OR MCPR.

LINEAR HEAT GENERATION RATE

1.19 LINEAR HEAT GENERATION RATE (LHGR) shall be the heat generation per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.

OPERATIONAL CONDITION - CONDITION

1.26 An OPERATIONAL CONDITION, i.e., CONDITION, shall be any one inclusive combination of mode switch position and average reactor coolant tempera-ture as specified in Table 1.2.

PHYSICS TESTS

1.27 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PLANT PROTECTION SYSTEM RESPONSE TIME

1.27a PLANT PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component (e.g., de-energization of the scram pilot valve solenoids, the valves travel to their required positions, pump discharge pressures reach their required values, isolation valves travel to their required positions). Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured. In lieu of measurement, a fixed response time may be applied for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

PRESSURE BOUNDARY LEAKAGE

1.28 PRESSURE BOUNDARY LEAKAGE shall be leakage through a nonisolable fault in a reactor coolant system component body, pipe wall or vessel wall.

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

1.28a The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current vessel fluence period. The pressure and temperature limits shall be determined for each fluence period in accordance with Specification 6.9.1.13.

PRIMARY CONTAINMENT INTEGRITY

1.29 PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All primary containment penetrations required to be closed during accident conditions are either:

1. Capable of being closed by an OPERABLE primary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except for valves that are opened under administrative control as permitted by Specification 3.6.3.

b. All primary containment equipment hatches are closed and sealed.

c. The primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. The primary containment leakage rates are within the limits of Specification 3.6.1.2.

e. The suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

f. The sealing mechanism associated with each primary containment penetration; e.g., welds, bellows, or O-rings, is OPERABLE.

PROCESS CONTROL PROGRAM

1.30 The PROCESS CONTROL PROGRAM (PCP) shall contain the provisions to assure that the solidification or dewatering and packaging of radioactive wastes results in a waste package with properties that meet the minimum and stability requirements of 10 CFR Part 61 and other requirements for transportation to the disposal site and receipt at the disposal site. With solidification or dewatering, the PCP shall identify the process parameters influencing solidification or dewatering, based on laboratory scale and full scale testing or experience.

PURGE - PURGING

1.31 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.32 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3515 MWt.

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

1.33 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All reactor enclosure secondary containment penetrations required to be closed during accident conditions are either:

1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, slide gate damper, or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.1.

b. All reactor enclosure secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. The reactor enclosure recirculation system is in compliance with the requirements of Specification 3.6.5.4.

e. At least one door in each access to the reactor enclosure secondary containment is closed except when the access opening is being used for entry and exit.

f. The sealing mechanism associated with each reactor enclosure secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

g. The pressure within the reactor enclosure secondary containment is less than or equal to the value required by Specification 4.6.5.1.1a, except as indicated by the footnote for Specification 4.6.5.1.1a.

1.34 (Deleted)

RECENTLY IRRADIATED FUEL

1.35 RECENTLY IRRADIATED FUEL is fuel that has occupied part of a critical reactor core within the previous 24 hours.

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY

1.36 REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All refueling floor secondary containment penetrations required to be closed during accident conditions are either:

DEFINITIONS

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY (Continued)

1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, slide gate damper, or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.2.

b. All refueling floor secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of specification 3.6.5.3.

d. At least one door in each access to the refueling floor secondary containment is closed except when the access opening is being used for entry and exit.

e. The sealing mechanism associated with each refueling floor secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

f. The pressure within the refueling floor secondary containment is less than or equal to the value required by Specification 4.6.5.1.2a, except as indicated by the footnote for Specification 4.6.5.1.2a.

REPORTABLE EVENT

1.37 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

RESTRICTED AREA

1.37a RESTRICTED AREA means an area, access to which is limited by the licensee for the purpose of protecting individuals against undue risks from exposure to radiation and radioactive materials. RESTRICTED AREA does not include areas used as residential quarters, but separate rooms in a residential building may be set apart as a RESTRICTED AREA.

SENSOR CHANNEL CALIBRATION

1.38 A SENSOR CHANNEL CALIBRATION shall be the adjustment, as necessary, of the sensor output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. Calibration of nonadjustable sensor channels, such as digital inputs, resistance temperature detectors (RTD) or thermocouples, may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the any remaining adjustable devices in the channel. Neutron detectors may be excluded from SENSOR CHANNEL CALIBRATION. The SENSOR CHANNEL CALIBRATION may be performed by any series of sequential, overlapping, or total channel steps such that the entire sensor channel is calibrated, and each step must be performed within the Frequency in the Surveillance Frequency Control Program for the devices included in the step.

SHUTDOWN MARGIN (SDM)

1.39 SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical throughout the operating cycle assuming that:

a. The reactor is xenon free;

b. The moderator temperature is ≥ 68°F, corresponding to the most reactive state; and

c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

SITE BOUNDARY

1.40 The SITE BOUNDARY shall be that line as defined in Figure 5.1.3-1a.

SOURCE CHECK

1.41 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

Unit 2

Proposed Technical Specifications

DRAIN TIME (Continued)

susceptible to a common mode failure (e.g., seismic event, loss of normal power, single human error), for all penetration flow paths below the TAF except:

1. Penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are locked, sealed, or otherwise secured in the closed position, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths;

2. Penetration flow paths capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation; or

3. Penetration flow paths with isolation devices that can be closed prior to the RPV water level being equal to the TAF by a dedicated operator trained in the task, who is in continuous communication with the control room, is stationed at the controls, and is capable of closing the penetration flow path isolation device without offsite power.

c) The penetration flow paths required to be evaluated per paragraph b) are assumed to open instantaneously and are not subsequently isolated, and no water is assumed to be subsequently added to the RPV water inventory;

d) No additional draining events occur; and

e) Realistic cross-sectional areas and drain rates are used.

A bounding DRAIN TIME may be used in lieu of a calculated value.

1.10 (Deleted)

1.11 (Deleted)

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

1.12 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker from initial movement of the associated:

a. Turbine stop valves, and
b. Turbine control valves.

This total system response time consists of two components, the instrumentation response time and the breaker arc suppression time. These times may be measured by any series of sequential, overlapping, or total steps such that the entire response time is measured.

1.13 (Deleted)
1.14 (Deleted)

FREQUENCY NOTATION

1.15 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

HIGH (POWER) TRIP SETPOINT (HTSP)

1.15a The high power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable above 85% reactor thermal power.

IDENTIFIED LEAKAGE

1.16 IDENTIFIED LEAKAGE shall be:

a. Leakage into collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of the leakage detection systems or not to be PRESSURE BOUNDARY LEAKAGE.

INSERVICE TESTING PROGRAM

1.16a The INSERVICE TESTING PROGRAM is the licensee program that fulfills the requirements of 10 CFR 50.55a(f).

INTERMEDIATE (POWER) TRIP SETPOINT (ITSP)

1.16b The intermediate power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable between 65% and 85% reactor thermal power.

1.17 (Deleted)

LIMITING CONTROL ROD PATTERN

1.18 A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, OR MCPR.

LINEAR HEAT GENERATION RATE

1.19 LINEAR HEAT GENERATION RATE (LHGR) shall be the heat generation per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.

OPERATIONAL CONDITION - CONDITION

1.26 An OPERATIONAL CONDITION, i.e., CONDITION, shall be any one inclusive combination of mode switch position and average reactor coolant temperature as specified in Table 1.2.

PHYSICS TESTS

1.27 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PLANT PROTECTION SYSTEM RESPONSE TIME

1.27a PLANT PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component (e.g., de-energization of the scram pilot valve solenoids, the valves travel to their required positions, pump discharge pressures reach their required values, isolation valves travel to their required positions). Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured. In lieu of measurement, a fixed response time may be applied for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

PRESSURE BOUNDARY LEAKAGE

1.28 PRESSURE BOUNDARY LEAKAGE shall be leakage through a nonisolable fault in a reactor coolant system component body, pipe wall or vessel wall. Leakage past seals, packing, and gaskets is not PRESSURE BOUNDARY LEAKAGE.

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

1.28a The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current vessel fluence period. The pressure and temperature limits shall be determined for each fluence period in accordance with Specification 6.9.1.13.

PRIMARY CONTAINMENT INTEGRITY

1.29 PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All primary containment penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE primary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except for valves that are opened under administrative control as permitted by Specification 3.6.3.

b. All primary containment equipment hatches are closed and sealed.

c. The primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. The primary containment leakage rates are within the limits of Specification 3.6.1.2.

e. The suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

f. The sealing mechanism associated with each primary containment penetration; e.g., welds, bellows, or O-rings, is OPERABLE.

PROCESS CONTROL PROGRAM

1.30 The PROCESS CONTROL PROGRAM (PCP) shall contain the provisions to assure that the solidification or dewatering and packaging of radioactive wastes results in a waste package with properties that meet the minimum and stability requirements of 10 CFR Part 61 and other requirements for transportation to the disposal site and receipt at the disposal site. With solidification or dewatering, the PCP shall identify the process parameters influencing solidification or dewatering, based on laboratory scale and full scale testing or experience.

PURGE - PURGING

1.31 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.32 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3515 MWt.

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

1.33 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All reactor enclosure secondary containment penetrations required to be closed during accident conditions are either:

1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, slide gate damper, or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.1.

b. All reactor enclosure secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. The reactor enclosure recirculation system is in compliance with the requirements of Specification 3.6.5.4.

e. At least one door in each access to the reactor enclosure secondary containment is closed except when the access opening is being used for entry and exit.

f. The sealing mechanism associated with each reactor enclosure secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

g. The pressure within the reactor enclosure secondary containment is less than or equal to the value required by Specification 4.6.5.1.1a, except as indicated by the footnote for Specification 4.6.5.1.1a.

1.34 (Deleted)

RECENTLY IRRADIATED FUEL

1.35 RECENTLY IRRADIATED FUEL is fuel that has occupied part of a critical reactor core within the previous 24 hours.

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY

1.36 REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All refueling floor secondary containment penetrations required to be closed during accident conditions are either:

DEFINITIONS

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY (Continued)

1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, slide gate damper, or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.2.

b. All refueling floor secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of specification 3.6.5.3.

d. At least one door in each access to the refueling floor secondary containment is closed except when the access opening is being used for entry and exit.

e. The sealing mechanism associated with each refueling floor secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

f. The pressure within the refueling floor secondary containment is less than or equal to the value required by Specification 4.6.5.1.2a, except as indicated by the footnote for Specification 4.6.5.1.2a.

REPORTABLE EVENT

1.37 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

RESTRICTED AREA

1.37a RESTRICTED AREA means an area, access to which is limited by the licensee for the purpose of protecting individuals against undue risks from exposure to radiation and radioactive materials. RESTRICTED AREA does not include areas used as residential quarters, but separate rooms in a residential building may be set apart as a RESTRICTED AREA.

SENSOR CHANNEL CALIBRATION

1.38 A SENSOR CHANNEL CALIBRATION shall be the adjustment, as necessary, of the sensor output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. Calibration of nonadjustable sensor channels, such as digital inputs, resistance temperature detectors (RTD) or thermocouples, may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the any remaining adjustable devices in the channel. Neutron detectors may be excluded from SENSOR CHANNEL CALIBRATION. The SENSOR CHANNEL CALIBRATION may be performed by any series of sequential, overlapping, or total channel steps such that the entire sensor channel is calibrated, and each step must be performed within the Frequency in the Surveillance Frequency Control Program for the devices included in the step.

SHUTDOWN MARGIN (SDM)

1.39 SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical throughout the operating cycle assuming that:

a. The reactor is xenon free;

b. The moderator temperature is ≥ 68°F, corresponding to the most reactive state; and

c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

SITE BOUNDARY

1.40 The SITE BOUNDARY shall be that line as defined in Figure 5.1.3-1a.

SOURCE CHECK

1.41 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

Unit 1

Revised Technical Specifications Bases (For Information Only)

None. Chapter 1 Does Not Have Bases.

Unit 2

Revised Technical Specifications Bases (For Information Only)

None. Chapter 1 Does Not Have Bases.

Section 2.2.1, Limiting Safety System Settings

Unit 1

Current Technical Specifications Markup

~~2.2 LIMITING SAFETY SYSTEM SETTINGS~~

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS~~

~~2.2.1 The reactor protection system instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2.1-1.~~

~~APPLICABILITY: As shown in Table 3.3.1-1.~~

D01

~~ACTION:~~

3.3.1 With a reactor protection system instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2.1-1, declare the channel inoperable* and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its setpoint adjusted consistent with the Trip Setpoint value.

3.3.1 *The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

Table 3.3.1-1

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ 120/125 divisions of full scale	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-Upscale (Setdown)	≤ 15.0% of RATED THERMAL POWER	≤ 20.0% of RATED THERMAL POWER
b. Simulated Thermal Power - Upscale:		
- Two Recirculation Loop Operation	≤ 0.65 W + 61.7% and ≤ 116.6% of RATED THERMAL POWER	≤ 0.65 W + 62.2% and ≤ 117.0% of RATED THERMAL POWER
- Single Recirculation Loop Operation***	≤ 0.65 (W-7.6%) + 61.5% and ≤ 116.6% of RATED THERMAL POWER	≤ 0.65 (W-7.6%) + 62.0% and ≤ 117.0% of RATED THERMAL POWER
c. Neutron Flux - Upscale	118.3% of RATED THERMAL POWER	118.7% of RATED THERMAL POWER
d. Inoperative	N.A.	N.A.
e. 2-Out-Of-4 Voter	N.A.	N.A.
f. OPRM Upscale	****	N.A.
3. Reactor Vessel Steam Dome Pressure - High	≤ 1096 psig	≤ 1103 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 12.5 inches above instrument zero*	≥ 11.0 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	≤ 8% closed	≤ 12% closed
6. DELETED	DELETED	DELETED
7. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
8. Scram Discharge Volume Water Level - High		
a. Level Transmitter	≤ 260' 9 5/8" elevation~~**~~	≤ 261' 5 5/8" elevation
b. Float Switch	≤ 260' 9 5/8" elevation**	≤ 261' 5 5/8" elevation
9. Turbine Stop Valve - Closure	≤ 5% closed	≤7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 500 psig	≥ 465 psig
11. Reactor Mode Switch Shutdown Position	N.A.	N.A.
12. Manual Scram	N.A.	N.A.

* See Bases Figure B 3/4.3-1.
** Equivalent to 25.45 gallons/scram discharge volume.
*** The 7.6% flow "offset" for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero.
**** See COLR for OPRM period based detection algorithm trip setpoints. OPRM Upscale trip output auto-enable (not bypassed) setpoints shall be APRM Simulated Thermal Power ≥ 29.5% and recirculation drive flow < 60%.

D01

Unit 2

Current Technical Specifications Markup

~~2.2 LIMITING SAFETY SYSTEM SETTINGS~~

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS~~

~~2.2.1 The reactor protection system instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2.1-1.~~

~~APPLICABILITY: As shown in Table 3.3.1-1.~~

D01

~~ACTION:~~

3.3.1 With a reactor protection system instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2.1-1, declare the channel inoperable* and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its setpoint adjusted consistent with the Trip Setpoint value.

3.3.1 *The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ 120/125 divisions of full scale	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-Upscale (Setdown)	≤ 15.0% of RATED THERMAL POWER	≤ 20.0% of RATED THERMAL POWER
b. Simulated Thermal Power - Upscale:		
- Two Recirculation Loop Operation	≤ 0.65 W + 61.7% and ≤ 116.6% of RATED THERMAL POWER	≤ 0.65 W + 62.2% and ≤ 117.0% of RATED THERMAL POWER
- Single Recirculation Loop Operation***	≤ 0.65 (W-7.6%) + 61.5% and ≤ 116.6% of RATED THERMAL POWER	≤ 0.65 (W-7.6%) + 62.0% and ≤ 117.0% of RATED THERMAL POWER
c. Neutron Flux - Upscale	118.3% of RATED THERMAL POWER	118.7% of RATED THERMAL POWER
d. Inoperative	N.A.	N.A.
e. 2-Out-Of-4 Voter	N.A.	N.A.
f. OPRM Upscale	****	N.A.
3. Reactor Vessel Steam Dome Pressure - High	≤ 1096 psig	≤ 1103 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 12.5 inches above instrument zero*	≥ 11.0 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	≤ 8% closed	≤ 12% closed
6. DELETED	DELETED	DELETED
7. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
8. Scram Discharge Volume Water Level - High		
a. Level Transmitter	≤ 261' 1 1/4" elevation**	≤ 261' 9 1/4" elevation
b. Float Switch	≤ 261' 1 1/4" elevation**	≤ 261' 9 1/4" elevation

Table 3.3.1-1

D01

* See Bases Figure B 3/4.3-1.

** Equivalent to 25.58 gallons/scram discharge volume.

*** The 7.6% flow "offset" for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero.

**** See COLR for OPRM period based detection algorithm trip setpoints. OPRM Upscale trip output auto-enable (not bypassed) setpoints shall be APRM Simulated Thermal Power ≥ 29.5% and recirculation drive flow < 60%.

TABLE 2.2.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
9. Turbine Stop Valve - Closure	≤ 5% closed	≤ 7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 500 psig	≥ 465 psig
11. Reactor Mode Switch Shutdown Position	N.A.	N.A.
12. Manual Scram	N.A.	N.A.

Table 3.3.1-1

D01

Discussion of Changes

Discussion of Changes

Technical Specification 2.2.1
Limiting Safety System Settings

D01

Current TS 2.2.1, "Limiting Safety System Settings," (LSSS) requires the RPS Instrumentation setpoints to be set consistent with the Trip Setpoints in TS Table 2.2.1-1, "Reactor Protection System Instrumentation Setpoints." The TS 2.2.1 Action directs that the Actions in TS 3.3.1 be followed if any RPS instrument setpoints are less conservative than the Allowable Value. The list of Functional Units in TS Table 2.2.1-1 are the same as the Functional Units in the tables of TS 3.3.1. Other instrumentation specifications in Section 3.3 contain a table of Functional Units, Trip Setpoints, and Allowable Values consistent with TS Table 2.2.1-1 in the respective specification. The proposed change moves the requirements in TS Table 2.2.1-1 and the Action to proposed TS 3.3.1, "Plant Protection System Instrumentation Channels." The remaining requirements in TS 2.2.1 are duplicative of TS 3.3.1 and are removed. The current TS 2.2.1 Action is modified by a footnote regarding APRM Simulated Thermal power - Upscale operability. This information is also moved to proposed TS 3.3.1.

The proposed change is acceptable because it is an administrative movement of information from TS Table 2.2.1-1 to proposed TS 3.3.1. No technical changes are made as part of the movement of the information. Any changes to the contents of the table, action, or footnote are discussed in the proposed changes to TS 3.3.1. In addition, the proposed change is consistent with NUREG-1433 STS which relocated all LSSS requirements to TS 3.3.1 and eliminated the LSSS section from the TS.

Unit 1

Proposed Technical Specifications

None. Specification Deleted.

Unit 2

Proposed Technical Specifications

None. Specification Deleted.

Unit 1

Revised Technical Specifications Bases (For Information Only)

~~2.2 LIMITING SAFETY SYSTEM SETTINGS~~

BASES

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

3.3.1 The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each parameter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. All four voters will trip (full scram) when any two unbypassed APRM channels exceed their trip setpoints.

APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) scram setting of 15% of RATED THERMAL POWER provides adequate thermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit.
3.3.1 The 15% Neutron Flux - Upscale (Setdown) trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux - Upscale setpoint; i.e., for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Simulated Thermal Power - Upscale setpoint, a time constant of 6 ± 0.6 seconds is introduced into the flow-biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow-biased setpoint as shown in Table 2.2.1-1.

A reduced Trip Setpoint and Allowable Value is provided for the Simulated Thermal Power – Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Trip Setpoint and Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Trip Setpoint and Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Trip Setpoint and Allowable Value equations for single loop operation are only valid for flows down to W = 7.6%. The Trip Setpoint and Allowable Value do not go below 61.5% and 62.0% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 1).

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unnecessary shutdown.

The APRM channels also include an Oscillation Power Range Monitor (OPRM) Upscale Function. The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into “cells” for evaluation by the OPRM algorithms.

References 2, 3 and 4 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.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. (NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. Refer to TS Bases 3/4.3.1 for further discussion concerning the recirculation drive flow/core flow relationship.) This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. See Reference 5 for additional discussion of OPRM Upscale trip enable region limits. These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Upscale trip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region.

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
3.3.1 flux, indicated by the combined signals of the LPRM detectors in a 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 oscillatory changes in the neutron flux for one or more cells in that channel.

There are four "sets" of OPRM related setpoints or adjustment parameters: a) OPRM trip auto-enable setpoints for APRM Simulated Thermal Power (29.5%) and recirculation drive flow (60%); b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; c) period based detection algorithm tuning parameters; and d) growth rate algorithm (GRA) and amplitude based algorithm (ABA) setpoints.

The first set, the OPRM auto-enable region setpoints, are treated as nominal setpoints with no additional margins added as discussed in Reference 5. The settings, 29.5% APRM Simulated Thermal Power and 60% recirculation drive flow, are defined (limit values) in a note to Table 2.2.1-1. The second set, the OPRM PBDA trip setpoints, are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. There are no allowable values for these setpoints. The third set, the OPRM PBDA "tuning" parameters, are established or adjusted in accordance with and controlled by station procedures. The fourth set, the GRA and ABA setpoints, in accordance with References 2 and 3, are established as nominal values only, and controlled by station procedures.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine stop valve and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

~~INTENTIONALLY LEFT BLANK~~

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint has been used in transient analyses dealing with coolant inventory decrease. The scram setting was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Main Steam Line Isolation Valve-Closure

3.3.1

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

6. DELETED

7 Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems or a loss of drywell cooling. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant and to the primary containment. The trip setting was selected as low as possible without causing spurious trips.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of 25.45 gallons of water.

3.3.1

9. Turbine Stop Valve-Closure

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position is a redundant channel to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

3.3.1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

REFERENCES:

1. NEDC-31300, “Single-Loop Operation Analysis for Limerick Generating Station, Unit 1,” August 1986.

2. NEDO-31960-A, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

3. NEDO-31960-A, Supplement 1, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.

5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), “Guidelines for Stability Option III ‘Enable Region’ (TAC M92882),” September 17, 1996.

Unit 2

Revised Technical Specifications Bases (For Information Only)

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each para-meter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

3/4.3.1

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. All four voters will trip (full scram) when any two unbypassed APRM channels exceed their trip setpoints.

APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) scram setting of 15% of RATED THERMAL POWER provides adequate hermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Tempera-ture coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

3/4.3.1 Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 15% Neutron Flux - Upscale (Setdown) trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux - Upscale setpoint; i.e., for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Simulated Thermal Power - Upscale setpoint, a time constant of 6 ± 0.6 seconds is introduced into the flow-biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow-biased setpoint as shown in Table 2.2.1-1.

A reduced Trip Setpoint and Allowable Value is provided for the Simulated Thermal Power – Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Trip Setpoint and Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Trip Setpoint and Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Trip Setpoint and Allowable Value equations for single loop operation are only valid for flows down to W = 7.6%. The Trip Setpoint and Allowable Value do not go below 61.5% and 62.0% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 1).

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unneces-sary shutdown.

The APRM channels also include an Oscillation Power Range Monitor (OPRM) Upscale Function. The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into “cells” for evaluation by the OPRM algorithms.

References 2, 3 and 4 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.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. (NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. Refer to TS Bases 3/4.3.1 for further discussion concerning the recirculation drive flow/core flow relationship.) This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. See Reference 5 for additional discussion of OPRM Upscale trip enable region limits. These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Upscale rip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband
3/4.3.1 while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region.

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 a 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 oscillatory changes in the neutron flux for one or more cells in that channel.

There are four "sets" of OPRM related setpoints or adjustment parameters: a) OPRM trip auto-enable setpoints for APRM Simulated Thermal Power (29.5%) and recirculation drive flow (60%); b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; c) period based detection algorithm tuning parameters; and d) growth rate algorithm (GRA) and amplitude based algorithm (ABA) setpoints.

The first set, the OPRM auto-enable region setpoints, are treated as nominal setpoints with no additional margins added as discussed in Reference 5. The settings, 29.5% APRM Simulated Thermal Power and 60% recirculation drive flow, are defined (limit values) in a note to Table 2.2.1-1. The second set, the OPRM PBDA trip setpoints, are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. There are no allowable values for these setpoints. The third set, the OPRM PBDA "tuning" parameters, are established or adjusted in accordance with and controlled by station procedures. The fourth set, the GRA and ABA setpoints, in accordance with References 2 and 3, are established as nominal values only, and controlled by station procedures.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine stop valve and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

~~INTENTIONALLY LEFT BLANK~~

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint has been used in transient analyses dealing with coolant inventory decrease. The scram setting was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel
3/4.3.1 and pressure limits.

5. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

6. DELETED

7. Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems or a loss of drywell cooling. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant and to the primary containment. The trip setting was selected as low as possible without causing spurious trips.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of 25.58 gallons of water.

9. Turbine Stop Valve-Closure

3/4.3.1

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position is a redundant channel to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

3/4.3.1

REFERENCES:

1. NEDC-31300, “Single-Loop Operation Analysis for Limerick Generating Station, Unit 1,” August 1986.
2. NEDO-31960-A, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.
3. NEDO-31960-A, Supplement 1, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.
4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.
5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), “Guidelines for Stability Option III ‘Enable Region’ (TAC M92882),” September 17, 1996.

Specification 3/4.3.1, Plant Protection System Instrumentation Channels

Unit 1

Current Technical Specifications Markup

3/4.3 INSTRUMENTATION

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

~~3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

D01

LIMITING CONDITION FOR OPERATION

The plant protection system

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

3.3.2 TIME as shown in Table 3.3.1-2.

APPLICABILITY: As shown in Table 3.3.1-1.

D05

ACTION:

Function

Note: Separate condition entry is allowed for each ~~channel~~.

Table 3.3.1-1 Note (b) ~~Note:~~ When Functional Unit 2.b and 2.c channels are inoperable due to the calculated power exceeding the APRM output by more than 2% of RATED THERMAL POWER while operating at ≥ 25% of RATED THERMAL POWER, entry into the associated Actions may be delayed up to 2 hours.

Insert 1

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

D03

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

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

~~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.~~

~~*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.~~

D03

~~**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.~~

Specification 3/4.3.1

Insert 1

a. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions one less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 12 hours:

   1. Place the required inoperable channel in the tripped condition#, or

   2. Initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

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

b. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions two or more less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 6 hours:

   1. Place the required inoperable channels in the tripped condition#, or

   2. Place one required inoperable channel in the trip condition# and initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

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

c. In OPERATIONAL CONDITION 4, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour verify all insertable control rods to be inserted in the core* and lock the reactor mode switch in the Shutdown position within 1 hour.

d. In OPERATIONAL CONDITION 5, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour place the inoperable channels in the tripped condition, or within 1 hour suspend all operations involving CORE ALTERATIONS and insert all insertable control rods*.

----

* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

For permissive Functions 3.c.2, 4.c, 11, and 12, Actions a.1 and b.1 are not applicable. For these functional units inoperable channel(s) shall be placed in bypass instead of trip to comply with Action b.2.

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

3/4.3 INSTRUMENTATION

~~3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

SURVEILLANCE REQUIREMENTS

Insert 2

~~4.3.1.1 Each reactor protection system 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 4.3.1.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.1.1-1.~~ D04

~~4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program, except Table 4.3.1.1-1 Functions 2.a, 2.b, 2.c, 2.d, 2.e and 2.f. Functions 2.a, 2.b, 2.c, 2.d, and 2.f do not require separate LOGIC SYSTEM FUNCTIONAL TESTS. For Function 2.e, tests shall be performed in accordance with the Surveillance Frequency Control Program. LOGIC SYSTEM FUNCTIONAL TEST for Function 2.e includes simulating APRM and OPRM trip conditions at the APRM channel inputs to the voter channel to check all combinations of two tripped inputs to the 2-Out-Of-4 voter logic in the voter channels.~~

3.3.2 4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its 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 reactor trip system.

Specification 3/4.3.1

Insert 2
Page 1

4.3.1.1 Each plant protection system instrumentation channel except for Function 1, "Intermediate Range Monitors," and Function 2, "Average Power Range Monitors," shall be demonstrated OPERABLE by the performance of a SENSOR CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.2 The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.

4.3.1.3 Each IRM Neutron Flux - High channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCITONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Neutron detectors may be excluded from CHANNEL CALIBRATION.

4.3.1.4 Each IRM Inoperative channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.5 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale, Neutron Flux - Upscale, 2-Out-Of-4 Voter, and OPRM Upscale function shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.6 Each APRM Neutron Flux - Upscale (Setdown)*, Simulated Thermal Power - Upscale**, Neutron Flux - Upscale, Inoperative, 2-Out-Of-4 Voter, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.7 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale***, Neutron Flux - Upscale***, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Calibration includes verification that the OPRM Upscale trip auto-enable (not-bypass) setpoint for APRM Simulated Thermal Power is ≥ 29.5% and for recirculation drive flow is < 60%.

4.3.1.8 The APRM LPRM inputs shall be calibrated at least once per 2000 effective full power hours (EFPH).

Specification 3/4.3.1

Insert 2
Page 2

4.3.1.9 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of the Turbine Stop Valve - Closure and the Turbine Control Valve - Fast Closure End-of-Cycle Recirculation Pump Trip System Functions shall be performed in accordance with the Surveillance Frequency Control Program.

----

* Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

** The CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.

*** Calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED THERMAL POWER. Verify the calculated power does not exceed the APRM channels by greater than 2% of RATED THERMAL POWER.

PTS

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

D01

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

Table 3.3.1-1

Function	~~FUNCTIONAL UNIT~~	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (a)~~ D10	ACTION (See Actions for Changes)
1	1. Intermediate Range Monitors~~(b)~~ (a):			
	a. Neutron Flux - High	2 3~~(i)~~, 4~~(i)~~ 5~~(i)~~ (f)	6 ~~3~~ ~~3~~ ~~3(d)~~ D07	1 2 3
	b. Inoperative	2 3~~(i)~~, 4~~(i)~~ 5~~(i)~~ (f)	6 ~~3~~ ~~3~~ ~~3(d)~~	1 2 3
2	2. Average Power Range Monitor~~(e)~~ (b):			
	a. Neutron Flux - Upscale (Setdown)	2	3~~(m)~~	1
	b. Simulated Thermal Power - Upscale	1	3~~(m)~~	4
	c. Neutron Flux - Upscale	1	3~~(m)~~ D08	4
	d. Inoperative	1, 2	3~~(m)~~ D14	1
	e. 2-Out-Of-4 Voter	1, 2	4 ~~2~~	1
	f. OPRM Upscale	1~~(o)(p)~~ (c) (d)	3~~(m)~~	10
3.a	3. Reactor Vessel Steam Dome Pressure - High	1, 2~~(f)~~ (k)	3 ~~2~~	1
5	4. Reactor Vessel Water Level - Low, Level 3	1, 2, 3 D11	3 ~~2~~ D10	1
19	5. Main Steam Line Isolation Valve-Closure	1(g)	3 ~~1/valve~~	4

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE 3.3.1-1 (Continued)

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

D01

PTS

D10

See Actions for Changes

Table 3.3.1-1 Function	FUNCTIONAL ~~UNIT~~	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (a)~~	ACTION
	6. ~~DELETED~~	~~DELETED~~	~~DELETED~~	~~DELETED~~
8	7. Drywell Pressure - High	1, 2~~(h)~~ (s)	3 ~~2~~	1
6	8. Scram Discharge Volume Water Level - High			
	a. Level Transmitter	1, 2 5~~(i)~~ (f)	3 ~~2~~ 3 ~~2~~	1 3
	b. Float Switch	1, 2 5~~(i)~~ (f)	3 ~~2~~ 3 ~~2~~	1 3
20	9. Turbine Stop Valve - Closure	1~~(j)~~ (h)	3 ~~4~~~~(k)~~	6
21	10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	1~~(j)~~ (h)	3 ~~2~~~~(k)~~	6
7	11. Reactor Mode Switch Shutdown Position	1, 2 3, 4 5	3 ~~2~~ ~~2~~ ~~2~~	1 7 3
	~~12. Manual Scram~~	~~1, 2~~ ~~3, 4~~ ~~5~~	~~2~~ ~~2~~ ~~2~~	~~1~~ ~~8~~ ~~9~~

D10

D09

D06

D01

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE 3.3.1-1 (Continued)

PTS

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

3.3.1 Actions

ACTION STATEMENTS

a.1 and b.1 ~~ACTION 1~~ - Be in at least HOT SHUTDOWN within 12 hours.

c, 2 ~~ACTION 2~~ - Verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within 1 hour.

d, 16 ~~ACTION 3~~ - Suspend all operations involving CORE ALTERATIONS and insert all insertable control rods within 1 hour.

14 ~~ACTION 4~~ - Be in at least STARTUP within 6 hours.

~~ACTION 5~~ - ~~Be in STARTUP with the main steam line isolation valves closed within 6 hours or in at least HOT SHUTDOWN within 12 hours.~~

Not referenced in Table 3.3.1-1

1 ~~ACTION 6~~ - Initiate a reduction in THERMAL POWER within 15 minutes and reduce turbine first stage pressure until the function is automatically bypassed, within 2 hours.

15 ~~ACTION 7~~ - Verify all insertable control rods to be inserted within 1 hour.

~~ACTION 8~~ - ~~Lock the reactor mode switch in the Shutdown position within 1 hour.~~ D06

~~ACTION 9~~ - ~~Suspend all operations involving CORE ALTERATIONS, and insert all insertable control rods and lock the reactor mode switch in the Shutdown position within 1 hour.~~ D06

3.3.1 Action d. ~~ACTION 10~~ -

a. If the condition exists due to a common-mode OPRM deficiency*, then initiate alternate method to detect and suppress thermal-hydraulic instability oscillations within 12 hours AND restore required channels to OPERABLE status within 120 days,

OR

b. Reduce THERMAL POWER to < 25% RATED THERMAL POWER within 4 hours.

~~* Unanticipated characteristic of the instability detection algorithm or equipment that renders all OPRM channels inoperable at once.~~ D09

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE 3.3.1-1 (Continued)

D01

PTS

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

TABLE NOTATIONS

(r) ~~(a)~~ 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 provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

(a) ~~(b)~~ This function shall be automatically bypassed when the reactor mode switch is in the Run position.

~~(c)~~ ~~DELETED~~

~~(d)~~ ~~The noncoincident NMS reactor trip function logic is such that all channels go to both trip systems. Therefore, when the "shorting links" are removed, the Minimum OPERABLE Channels Per Trip System is 6 IRMs.~~ D07

(b) ~~(e)~~ An APRM channel is inoperable if there are less than 3 LPRM inputs per level or less than 20 LPRM inputs to an APRM channel, or if more than 9 LPRM inputs to the APRM channel have been bypassed since the last APRM calibration (weekly gain calibration).

(k) ~~(f)~~ This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(g) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(s) ~~(h)~~ This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(f) ~~(i)~~ With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(h) ~~(j)~~ This function shall be automatically bypassed when turbine first stage pressure is equivalent to a THERMAL POWER of less than 29.5% of RATED THERMAL POWER.

~~(k)~~ ~~Also actuates the EOC-RPT system.~~ D09

~~(l)~~ ~~DELETED~~

~~(m)~~ ~~Each APRM channel provides inputs to both trip systems.~~ D08

~~(n)~~ ~~DELETED~~

(c) ~~(o)~~ With THERMAL POWER ≥ 25% RATED THERMAL POWER. The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60%. The OPRM trip output may be automatically bypassed when APRM Simulated Thermal Power is < 29.5% or recirculation drive flow is ≥ 60%.

(d) ~~(p)~~ A minimum of 23 cells, each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for an OPRM channel to be OPERABLE.

3.3.2

TABLE 3.1-2

REACTOR PROTECTION SYSTEM RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME (Seconds)
1. Intermediate Range Monitors:	
a. Neutron Flux - High	N.A.
b. Inoperative	N.A.
2. Average Power Range Monitor*:	
a. Neutron Flux - Upscale (Setdown)	N.A.
b. Simulated Thermal Power - Upscale	N.A.
c. Neutron Flux - Upscale	N.A.
d. Inoperative	N.A.
e. 2-Out-Of-4 Voter	≤0.05*
f. OPRM Upscale	N.A.
3. Reactor Vessel Steam Dome Pressure - High	≤0.55
4. Reactor Vessel Water Level - Low, Level 3	≤1.05#
5. Main Steam Line Isolation Valve - Closure	≤0.06
6. DELETED	DELETED
7. Drywell Pressure - High	N.A.
8. Scram Discharge Volume Water Level - High	
a. Level Transmitter	N.A.
b. Float Switch	N.A.
9. Turbine Stop Valve - Closure	≤0.06
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≤0.08**
11. Reactor Mode Switch Shutdown Position	N.A.
12. Manual Scram	N.A.

* Neutron detectors, APRM channel and 2-Out-Of-4 Voter channel digital electronics are exempt from response time testing. Response time shall be measured from activation of the 2-Out-Of-4 Voter output relay. For applications of Specification 4.3.1.3, the redundant outputs from each 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8. Testing of OPRM and APRM outputs shall alternate.

** Measured from start of turbine control valve fast closure.

\# Sensor is eliminated from response time testing for the RPS circuits. Response time testing and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required.

D01

D04

~~TABLE 4.3.1.1-1~~

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

See changes to Table 3.3.1-1

PTS

	FUNCTIONAL UNIT	CHANNEL CHECK(n)	CHANNEL FUNCTIONAL TEST(n)	CHANNEL CALIBRATION(a)~~(n)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
4.3.1.2	1. Intermediate Range Monitors:				
4.3.1.3	a. Neutron Flux - High	(b)	~~(j)~~		2 3(i), 4(i), 5(i)
4.3.1.4	b. Inoperative	N.A.	~~(j)~~	N.A.	2, 3(i), 4(i), 5(i)
	2. Average Power Range Monitor(f):				
	a. Neutron Flux - Upscale (Setdown)	(b)	~~(l)~~ *		2
4.3.1.5, 4.3.1.6, 4.3.1.7, 4.3.1.8, 4.3.1.9	b. Simulated Thermal Power - Upscale		(e)	(d), ~~(g)~~, ~~(o), (p)~~	1
	c. Neutron Flux - Upscale			(d)	1
	d. Inoperative	N.A.		N.A.	1, 2
	e. 2-Out-Of-4 Voter			N.A.	1, 2
	f. OPRM Upscale		(e)	(c)~~(g)~~	1(m)
4.3.1.1	3. Reactor Vessel Steam Dome Pressure - High				~~1, 2(h)~~
4.3.1.1	4. Reactor Vessel Water Level-Low, Level 3				~~1, 2~~
4.3.1.1	5. Main Steam Line Isolation Valve - Closure	~~N.A.~~			~~1~~
	~~6. DELETED~~				
4.3.1.1	7. Drywell Pressure - High				~~1, 2~~
4.3.1.1	8. Scram Discharge Volume Water Level - High				
	a. Level Transmitter				~~1, 2, 5(i)~~
	b. Float Switch	~~N.A.~~			~~1, 2, 5(i)~~

D07

D13

D12

D13

D04

PTS

SR or Table 4.3.1-1 Note

D01 D04

~~TABLE 4.3.1.1-1 (Continued)~~

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

See changes to Table 3.3.1-1

	FUNCTIONAL UNIT	CHANNEL CHECK~~(n)~~	CHANNEL FUNCTIONAL TEST~~(n)~~	CHANNEL CALIBRATION(a)~~(n)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
4.3.1.1	9. Turbine Stop Valve - Closure	~~N.A.~~			~~1~~
4.3.1.1	10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	~~N.A.~~			~~1~~
4.3.1.1	11. Reactor Mode Switch Shutdown Position	~~N.A.~~		~~N.A.~~	~~1, 2, 3, 4, 5~~
	~~12. Manual Scram~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3, 4, 5~~

D04 D06

Moved to SENSOR CHANNEL CALIBRATION definition.

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

4.3.1.2 (b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.

4.3.1.7 (c) Calibration includes verification that the OPRM Upscale trip auto-enable (not-bypass) setpoint for APRM Simulated Thermal Power is ≥ 29.5% and for recirculation drive flow is < 60%.

*** (d) The ~~more frequent~~ calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED THERMAL POWER. Verify the calculated power does not exceed the APRM channels by greater than 2% of RATED THERMAL POWER.

4.3.1.8 (e) CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.

(f) The LPRMs shall be calibrated at least once per 2000 effective full power hours (EFPH).

~~(g) The less frequent calibration includes the flow input function.~~

D13

Note (k) ~~(h)~~ This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

Note (f) ~~(i)~~ With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

~~(j) If the RPS shorting links are required to be removed per Specification 3.9.2, they may be reinstalled for up to 2 hours for required surveillance. During this time, CORE ALTERATIONS shall be suspended, and no control rod shall be moved from its existing position.~~

D07

~~(k) DELETED~~

Note * ~~(l)~~ Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

~~(m) With THERMAL POWER ≥ 25% of RATED THERMAL POWER.~~

~~(n) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.~~

D04

~~TABLE 4.3.1.1-1 (Continued)~~

D01

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

D12

~~(o) If the as-found channel setpoint is outside its predefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.~~

~~(p) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Trip Setpoint at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the Trip Setpoint are acceptable provided that the as found and as left tolerances apply to the actual setpoint implemented in the surveillance procedures (field setting) to confirm channel performance. The methodologies used to determine the as found and the as-left tolerances are specified in the associated Technical Specifications Bases.~~

PTS

SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

2.2.1 2.2.1 The reactor protection system instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2.1-1.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

~~With a reactor protection system instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2.1-1, declare the channel inoperable* and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its setpoint adjusted consistent with the Trip Setpoint value.~~ D02

Table 3.3.1-1 Notation (e). *The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

D01

PTS

~~TABLE 2.2.1-1~~

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS~~

FUNCTIONAL ~~UNIT~~	~~TRIP SETPOINT~~	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	~~≤ 120/125 divisions of full scale~~	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-Upscale (Setdown)	~~≤ 15.0% of RATED THERMAL POWER~~	≤ 20.0% of RATED THERMAL POWER
b. Simulated Thermal Power - Upscale:		
- Two Recirculation Loop Operation	~~≤ 0.65 W + 61.7% and ≤ 116.6% of RATED THERMAL POWER~~	≤ 0.65 W + 62.2% and ≤ 117.0% of RATED THERMAL POWER
- Single Recirculation Loop Operation***	~~≤ 0.65 (W-7.6%) + 61.5% and ≤ 116.6% of RATED THERMAL POWER~~	≤ 0.65 (W-7.6%) + 62.0% and ≤ 117.0% of RATED THERMAL POWER
c. Neutron Flux - Upscale	~~118.3% of RATED THERMAL POWER~~	118.7% of RATED THERMAL POWER
d. Inoperative	~~N.A.~~	N.A.
e. 2-Out-Of-4 Voter	~~N.A.~~	N.A.
f. OPRM Upscale	~~****~~	N.A.
3. Reactor Vessel Steam Dome Pressure - High	~~≤ 1096 psig~~	≤ 1103 psig
4. Reactor Vessel Water Level - Low, Level 3	~~≥ 12.5 inches above instrument zero*~~	≥ 11.0 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	~~≤ 8% closed~~	≤ 12% closed
~~6. DELETED~~	~~DELETED~~	~~DELETED~~
7. Drywell Pressure - High	~~≤ 1.68 psig~~	≤ 1.88 psig
8. Scram Discharge Volume Water Level - High		
a. Level Transmitter	~~≤ 260' 9 5/8"~~ elevation**	≤ 261' 5 5/8" elevation
b. Float Switch	~~≤ 260' 9 5/8"~~ elevation**	≤ 261' 5 5/8" elevation
9. Turbine Stop Valve - Closure	~~≤ 5% closed~~	≤7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	~~≥ 500 psig~~	≥ 465 psig
11. Reactor Mode Switch Shutdown Position	~~N.A.~~	N.A.
~~12. Manual Scram~~	~~N.A.~~	~~N.A.~~

D02

D06

Table 3.3.1-1 Note (e)

~~* See Bases Figure B 3/4.3-1.~~

~~** Equivalent to 25.45 gallons/scram discharge volume.~~

~~***~~The 7.6% flow "offset" for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero.

D09

~~**** See COLR for OPRM period based detection algorithm trip setpoints.~~ OPRM Upscale trip output auto-enable (not bypassed) setpoints shall be APRM Simulated Thermal Power ≥ 29.5% and recirculation drive flow < 60%.

Table 3.3.1-1 Note (c)

D02

INSTRUMENTATION

~~3/4.3.2. ISOLATION ACTUATION INSTRUMENTATION~~

D01

LIMITING CONDITION FOR OPERATION

3.3.1 ~~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.

D02

3.3.2

APPLICABILITY: As shown in Table 3.3.~~2~~-1.

1

D01

ACTION:

D02

~~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.~~

D03

~~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.~~
~~** Not applicable when trip capability is not maintained.~~
~~# Not applicable for Function 7, Secondary Containment Isolation.~~

D03

PTS

INSTRUMENTATION

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

~~c. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within 1 hour and take the ACTION required by Table 3.3.2-1.~~ D03

SURVEILLANCE REQUIREMENTS

~~4.3.2.1 Each isolation 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 4.3.2.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.2.1-1.~~

~~4.3.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operations of all channels shall be performed in accordance with the Surveillance Frequency Control Program.~~ D04

3.3.2 4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shown in Table 3.3.2-3 shall be demonstrated to be within its 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 accordance with the Surveillance Frequency Control Program, where N is the total number of redundant channels in a specific isolation trip system.

~~** The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition; if both systems have the same number of inoperable channels, place either trip system in the tripped condition.~~ D03

LIMERICK - UNIT 1

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

~~TABLE 3.3.2-1~~

~~ISOLATION ACTUATION INSTRUMENTATION~~

D01

PTS Table 3.3.1-1 Function	~~TRIP FUNCTION~~	~~ISOLATION SIGNAL (a)~~	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (b)~~	APPLICABLE OPERATIONAL CONDITION	ACTION	
	1. MAIN STEAM LINE ISOLATION				See Actions for Changes	D10, D09
	a. Reactor Vessel Water Level					
4.b	1) Low, Low-Level 2	~~B~~	3 ~~2~~	1, 2, 3	21	D10
4.a	2) Low, Low, Low-Level 1	~~C~~	3 ~~2~~	1, 2, 3	21	
	~~b. DELETED~~	~~DELETED~~	~~DELETED~~	~~DELETED~~	~~DELETED~~	
22	c. Main Steam Line Pressure - Low	~~P~~	3 ~~2~~	1	22	
23	d. Main Steam Line Flow - High	~~E~~	3/steam line ~~2/line~~	1, 2, 3 (i)	20	
24	e. Condenser Vacuum - Low	~~Q~~	3 ~~2~~	1, 2**, ~~3**~~	21	D09
25	f. Outboard MSIV Room Temperature - High	F~~(f)~~ (l)	3 ~~2~~	1, 2, 3	21	
3.7.9	g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	F(f)	14	1, 2, 3	21	
	~~h. Manual Initiation~~	~~NA~~	~~2~~	~~1, 2, 3~~	~~24~~	D06
	2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION					D09
5.a	a. Reactor Vessel Water Level Low - Level 3 -SDC	~~A~~	3 ~~2~~	1, 2, 3	23	
3.b	b. Reactor Vessel (RHR Cut-In ~~Permissive~~) Pressure - High	~~V~~	3 ~~2~~	1, 2, 3	23	D17
	c. ~~Manual Initiation~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~24~~	D06

D10

Amendment No. ~~28~~, ~~89~~

PTS

Table 3.3.1-1
Function

TS 3.3.1

~~TABLE 3.3.2-1 (Continued)~~
~~ISOLATION ACTUATION INSTRUMENTATION~~

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

ICK - UNIT 1

Function		TRIP FUNCTION	~~ISOLATION SIGNAL (a)~~	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (b)~~	APPLICABLE OPERATIONAL CONDITION	ACTION	Change
	3.	REACTOR WATER CLEANUP SYSTEM ISOLATION					D10, D09
26	a.	RWCS Δ Flow - High	~~J~~	2 ~~1~~	1, 2, 3	23	D10
27	b.	RWCS Area Temperature - High	~~J~~	12 ~~6~~	1, 2, 3	23	D15
28	c.	RWCS Area Ventilation Δ Temperature - High	~~J~~	12 ~~6~~	1, 2, 3	23	D15
29	d.	SLCS Initiation	~~Y(d)~~	NA	1, 2, 3	23	
4.b	e.	Reactor Vessel Water Level - Low, Low - Level 2	~~B~~	3 ~~2~~	1, 2, 3	23	D10
	~~f.~~	~~Manual Initiation~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~24~~	D06
	4.	HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION					D09
14	a.	HPCI Steam Line Δ Pressure - High	~~L~~	2 ~~1~~	1, 2, 3	23	D10
3.d	b.	HPCI Steam Supply Pressure - Low	~~LA~~	3 ~~2~~	1, 2, 3	23	D10
15	c.	HPCI Turbine Exhaust Diaphragm Pressure - High	~~L~~	3 ~~2~~	1, 2, 3	23	D10
16	d.	HPCI Equipment Room Temperature - High	~~L~~	2 ~~1~~	1, 2, 3	23	D10
17	e.	HPCI Equipment Room Δ Temperature - High	~~L~~	2 ~~1~~	1, 2, 3	23	D10

See Actions for Changes

D10

3/4 3-12

PTS

Table 3.3.1-1
Function

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

~~TABLE 3.3.2-1 (Continued)~~
~~ISOLATION ACTUATION INSTRUMENTATION~~

D01

~~TRIP FUNCTION~~	~~ISOLATION SIGNAL (a)~~	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (b)~~	APPLICABLE OPERATIONAL CONDITION	ACTION
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION (Continued)				
18 f. HPCI Pipe Routing Area Temperature - High	~~L~~	2 ~~4~~	1, 2, 3	23
~~g. Manual Initiation~~	~~NA(e)~~	~~1/system~~	~~1, 2, 3~~	~~24~~
3.3.2 h. HPCI Steam Line Δ Press Timer	NA	1	1, 2, 3	23
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
30 a. RCIC Steam Line Δ Pressure - High	~~K~~	2 ~~1~~	1, 2, 3	23
3.e b. RCIC Steam Supply Pressure - Low	~~KA~~	3 ~~2~~	1, 2, 3	23
31 c. RCIC Turbine Exhaust Diaphragm Pressure - High	~~K~~	3 ~~2~~	1, 2, 3	23
32 d. RCIC Equipment Room Temperature - High	~~K~~	2 ~~1~~	1, 2, 3	23
33 e. RCIC Equipment Room Δ Temperature - High	~~K~~	2 ~~1~~	1, 2, 3	23
35 f. RCIC Pipe Routing Area Temperature - High	~~K~~	10 ~~5~~	1, 2, 3	23
~~g. Manual Initiation~~	~~NA(e)~~	~~1/system~~	~~1, 2, 3~~	~~24~~
h. RCIC Steam Line Δ Pressure Timer	NA	1	1, 2, 3	23

D10 D09 D10 D06 D09 D10 D15 D06

3.3.2

See Actions for Changes

~~MERICK - UNIT 1~~

Amendment No. 33

OCT 30 1989

Table 3.3.1-1
PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.2-1 (Continued)~~
~~ISOLATION ACTUATION INSTRUMENTATION~~

D10

D09

PTS

Table 3.3.1-1 Function	~~TRIP FUNCTION~~	~~ISOLATION SIGNAL (a)~~	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION (See Actions for Changes)
	6. PRIMARY CONTAINMENT ISOLATION				
4.a	a. Reactor Vessel Water Level 1) Low, Low - Level 2	~~B~~	3 ~~2~~	1, 2, 3	20
4.b	2) Low, Low, Low - Level 1	~~C~~	3 ~~2~~	1, 2, 3	20
8	b. Drywell Pressure - High	~~H~~	3 ~~2~~	1, 2, 3	20
35	c. North Stack Effluent Radiation - High ~~(e)~~ (m)	~~W~~	2 ~~1~~	1, 2, 3	23
	~~d. Deleted~~				
36	e. Reactor Enclosure Ventilation Exhaust Duct-Radiation - High	~~S~~	3 ~~2~~	1, 2, 3	23
	~~f. Deleted~~				
	~~g. Deleted~~				
8 / 3.c	h. Drywell Pressure - High/ Reactor Pressure - Low	~~G~~	3 ~~2/2~~	1, 2, 3	~~26~~
9	i. Primary Containment Instrument Gas Line to Drywell Δ Pressure - Low	~~M~~	1/valve ~~1~~	1, 2, 3	26
	~~j. Manual Initiation~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~24~~

D10

D06

D10

PTS

Table 3.3.1-1
PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

~~TABLE 3.3.2-1 (Continued)~~
~~ISOLATION ACTUATION INSTRUMENTATION~~

D01

D10

D09

Table 3.3.1-1 Function	TRIP FUNCTION	~~ISOLATION SIGNAL (a),(c)~~	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (b)~~	APPLICABLE OPERATIONAL CONDITION	ACTION
	7. SECONDARY CONTAINMENT ISOLATION				
4.b	a. Reactor Vessel Water Level Low, Low - Level 2	~~B~~	3 ~~2~~	1, 2, 3	25
8	b. Drywell Pressure - High	~~H~~	3 ~~2~~	1, 2, 3	25
37	c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	~~R~~	3 ~~2~~	*#	25
38	2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	~~R~~	3 ~~2~~	*#	25
36	d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	~~S~~	3 ~~2~~	1, 2, 3	25
	~~e. Deleted~~				
	~~f. Deleted~~				
	~~g. Reactor Enclosure Manual Initiation~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~27~~
	~~h. Refueling Area Manual Initiation~~	~~NA~~	~~1~~	~~*~~	~~25~~

See Actions for Changes

D10

D06

PTS
3.3.1 Action

~~TABLE 3.3.2-1 (Continued)~~
~~ISOLATION ACTUATION INSTRUMENTATION~~
~~ACTION STATEMENTS~~

D01

a.3 and b.3 ~~ACTION 20~~ - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

3, a.3 and b.3 ACTION 21 - Be in at least STARTUP with the associated penetration flow path(s) isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 6 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

14 ~~ACTION 22~~ - Be in at least STARTUP within 6 hours.

4 ~~ACTION 23~~ - In OPERATIONAL CONDITION 1 or 2, verify the affected penetration flow path(s) are isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour and declare the affected system inoperable. In OPERATIONAL CONDITION 3, be in at least COLD SHUTDOWN within 12 hours.

~~ACTION 24 - Restore the manual initiation function to OPERABLE status within 8 hours or isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within the next hour and declare the affected system inoperable or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.~~ D06

6 ~~ACTION 25~~ - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

5 ~~ACTION 26~~ - Isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour.

~~ACTION 27 - Restore the manual initiation function to OPERABLE status within 8 hours or establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.~~ D06

TABLE NOTATIONS

* ~~Required when handling RECENTLY IRRADIATED FUEL in the secondary containment.~~

~~**~~ May be bypassed under administrative control, with all turbine stop valves closed.

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

\# During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

~~(a) DELETED~~

~~(b) 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 provided at least one OPERABLE channel in the same trip system is monitoring that parameter. Trip functions common to RPS Actuation Instrumentation are shown in Table 4.3.2.1-1. In addition, for the HPCI system and RCIC system isolation, provided that the redundant isolation valve, inboard or outboard, as applicable, in each line is OPERABLE and all required actuation instrumentation for that valve is OPERABLE, one channel may be placed in an inoperable status for up to 8 hours for required surveillance without placing the channel or trip system in the tripped condition.~~ D10

Table 3.3.1-1
Function 38 and 39
Applicability

PTS

D01

~~TABLE 3.3.2-1~~ ~~(Continued)~~

~~TABLE NOTATIONS~~

~~(c) Actuates secondary containment isolation valves. Signals B, H, S, and R also start the standby gas treatment system.~~

D09

~~(d) RWCU system inlet outboard isolation valve closes on SLCS "B" initiation. RWCU system inlet inboard isolation valve closes on SLCS "A" or SLCS "C" initiation.~~

~~(e) Manual initiation isolates the steam supply line outboard isolation valve and only following manual or automatic initiation of the system.~~ D06

(l) ~~(f)~~ In the event of a loss of ventilation the temperature - high setpoint may be raised by 50°F for a period not to exceed 30 minutes to permit restoration of the ventilation flow without a spurious trip. During the 30 minute period, an operator, or other qualified member of the technical staff, shall observe the temperature indications continuously, so that, in the event of rapid increases in temperature, the main steam lines shall be manually isolated.

(m) ~~(g)~~ Wide range accident monitor per Specification 3.3.7.5.

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.2-2~~

~~ISOLATION ACTUATION INSTRUMENTATION SETPOINTS~~

PTS

D02

TRIP FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE
1. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level		
1) Low, Low - Level 2	~~≥ - 38 inches*~~	≥ - 45 inches
2) Low, Low, Low - Level 1	~~≥ - 129 inches*~~	≥ - 136 inches
~~b. DELETED~~	~~DELETED~~	~~DELETED~~
c. Main Steam Line Pressure - Low	~~≥ 840 psig~~	≥ 821 psig
d. Main Steam Line Flow - High	~~≤ 122.1 psid~~	≤ 123 psid
e. Condenser Vacuum - Low	~~10.5 psia~~	≥10.1 psia/≤ 10.9 psia
f. Outboard MSIV Room Temperature - High	~~≤ 192°F~~	≤ 200°F
3.7.9 g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	≤ 165°F	≤ 175°F
~~h. Manual Initiation~~	~~N.A.~~	~~N.A.~~
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		
a. Reactor Vessel Water Level Low - Level 3	~~≥ 12.5 inches*~~	≥ 11.0 inches
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	~~≤ 75 psig~~	≤ 95 psig
~~c. Manual Initiation~~	~~N.A.~~	~~N.A.~~

D06

D02

D06

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

PTS

~~TABLE 3.3.2-2 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SETPOINTS~~

~~TRIP~~ FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE
3. REACTOR WATER CLEANUP SYSTEM ISOLATION		
a. RWCS Δ Flow - High	~~≤ 54.9 gpm~~	≤ 65.2 gpm
b. RWCS Area Temperature - High	~~≤ 155°F or ≤ 120°F**~~	≤ 160°F or ≤ 125°F**
c. RWCS Area Ventilation Δ Temperature - High	~~≤ 52°F or ≤ 32°F**~~	≤ 60°F or ≤ 40°F**
d. SLCS Initiation	~~N.A.~~	N.A.
e. Reactor Vessel Water Level - Low, Low, - Level 2	~~≥ -38 inches *~~	≥ -45 inches
~~f. Manual Initiation~~	~~N.A.~~	~~N.A.~~
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION		
a. HPCI Steam Line Δ Pressure - High	~~≤ 974"~~ H_2O	≤ 984" H_2O
b. HPCI Steam Supply Pressure - Low	~~≥ 100~~ psig	≥ 90 psig
c. HPCI Turbine Exhaust Diaphragm Pressure - High	~~≤ 10~~ psig	≤ 20 psig
d. HPCI Equipment Room Temperature - High	~~180°F~~	≥ 177°F, ≤ 191°F
e. HPCI Equipment Room Δ Temperature - High	~~≤ 104°F~~	≤ 108.5°F
f. HPCI Pipe Routing Area Temperature - High	~~180°F~~	≥ 177°F, ≤ 191°F
~~g. Manual Initiation~~	~~N.A.~~	~~N.A.~~
3.3.2 h. HPCI Steam Line Δ Pressure - Timer	3 ≤ τ ≤ 12.5 seconds	2.5 ≤ τ ≤ 13 seconds

D02

D06

D02

D06

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.2-2 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SETPOINTS~~

PTS

~~TRIP~~ FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a. RCIC Steam Line Δ Pressure - High	~~≤ 373" H_2O~~	≤ 381" H_2O
b. RCIC Steam Supply Pressure - Low	~~≥ 64.5 psig~~	≥ 56.5 psig
c. RCIC Turbine Exhaust Diaphragm Pressure - High	~~≤ 10.0 psig~~	≤ 20.0 psig
d. RCIC Equipment Room Temperature - High	~~180°F~~	≥ 161°F, ≤ 191°F
e. RCIC Equipment Room Δ Temperature - High	~~≤ 109°F~~	≤ 113.5°F
f. RCIC Pipe Routing Area Temperature - High	~~180°F~~	≥ 161°F, ≤ 191°F
~~g. Manual Initiation~~	~~N.A.~~	~~N.A.~~
h. RCIC Steam Line Δ Pressure Timer	3 ≤ τ ≤ 12.5 seconds	2.5 ≤ τ ≤ 13 seconds

D02

3.3.2

D06

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.2-2 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SETPOINTS~~

TRIP FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE
6. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level		
1. Low, Low - Level 2	~~≥ -38 inches*~~	≥ -45 inches
2. Low, Low, Low - Level 1	~~≥ -129 inches*~~	≥ -136 inches
b. Drywell Pressure - High	~~≤ 1.68 psig~~	≤ 1.88 psig
c. North Stack Effluent Radiation - High	~~≤ 2.1 µCi/cc~~	≤ 4.0 µCi/cc
~~d. Deleted~~		
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	~~≤ 1.35 mR/h~~	≤ 1.5 mR/h
~~f. Deleted~~		
~~g. Deleted~~		
h. Drywell Pressure - High/ Reactor Pressure - Low	~~≤ 1.68 psig/ ≥ 455 psig (decreasing)~~	≤ 1.88 psig/ ≥ 435 psig (decreasing)
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	~~≥ 2.0 psi~~	≥ 1.9 psi
~~j. Manual Initiation~~	~~N.A.~~	~~N.A.~~

D02

D06

PTS

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.2-2 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SETPOINTS~~

~~TRIP FUNCTION~~	~~TRIP SETPOINT~~	ALLOWABLE VALUE	
7. SECONDARY CONTAINMENT ISOLATION			
a. Reactor Vessel Water Level - Low, Low - Level 2	~~≥ -38 inches*~~	≥ -45 inches	
b. Drywell Pressure - High	~~≤ 1.68 psig~~	≤ 1.88 psig	
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	~~≤ 2.0 mR/h~~	≤ 2.2 mR/h	D02
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	~~≤ 2.0 mR/h~~	≤ 2.2 mR/h	
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	~~≤ 1.35 mR/h~~	≤ 1.5 mR/h	
~~e. Deleted~~			
~~f. Deleted~~			
~~g. Reactor Enclosure Manual Initiation~~	~~N.A.~~	~~N.A.~~	D06
~~h. Refueling Area Manual Initiation~~	~~N.A.~~	~~N.A.~~	D06

~~* See Bases Figure B 3/4 3-1.~~

** The low setpoints are for the RWCU Heat Exchanger Rooms; the high setpoints are for the pump rooms.

D09

Footnote (j)

FEB 14 1996

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

	TRIP FUNCTION	RESPONSE TIME (Seconds)#
	1. MAIN STEAM LINE ISOLATION	
	a. Reactor Vessel Water Level	
	1) Low, Low - Level 2	N.A.
	2) Low, Low, Low - Level 1	≤1.0 ###*
	b. DELETED	DELETED
	c. Main Steam Line Pressure - Low	≤1.0 ###*
	d. Main Steam Line Flow - High	≤1.0 ###*
3.3.2	e. Condenser Vacuum - Low	N.A.
	f. Outboard MSIV Room Temperature - High	N.A.
3.7.9	g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	N.A.
	h. Manual Initiation	N.A.
	2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
3.3.2	a. Reactor Vessel Water Level Low - Level 3	N.A.
	b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	N.A.
	c. Manual Initiation	N.A.
	3. REACTOR WATER CLEANUP SYSTEM ISOLATION	
	a. RWCS Δ Flow - High	N.A. ##
	b. RWCS Area Temperature - High	N.A.
	c. RWCS Area Ventilation Δ Temperature - High	N.A.
	d. SLCS Initiation	N.A.
	e. Reactor Vessel Water Level - Low, Low - Level 2	N.A.
	f. Manual Initiation	N.A.

PTS

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION	
a. HPCI Steam Line Δ Pressure - High	N.A.
b. HPCI Steam Supply Pressure - Low	N.A.
c. HPCI Turbine Exhaust Diaphragm Pressure - High	N.A.
d. HPCI Equipment Room Temperature - High	N.A.
e. HPCI Equipment Room Δ Temperature - High	N.A.
f. HPCI Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. RCIC Steam Line Δ Pressure - High	N.A.
b. RCIC Steam Supply Pressure - Low	N.A.
c. RCIC Turbine Exhaust Diaphragm Pressure - High	N.A.
d. RCIC Equipment Room Temperature - High	N.A.
e. RCIC Equipment Room Δ Temperature - High	N.A.
f. RCIC Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.

3.3.2

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
6. PRIMARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level	
1) Low, Low - Level 2	N.A.
2) Low, Low, Low - Level 1	N.A.
b. Drywell Pressure - High	N.A.
c. North Stack Effluent Radiation - High	N.A.
d. Deleted	
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	N.A.
f. Deleted	
g. Deleted	
3.3.2 h. Drywell Pressure - High/ Reactor Pressure - Low	N.A.
i. Primary Containment Instrument Gas to Drywell ▵ Pressure - Low	N.A.
j. Manual Initiation	N.A.
7. SECONDARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level Low, Low - Level 2	N.A.
b. Drywell Pressure - High	N.A.
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	N.A.
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	N.A.
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	N.A.
e. Deleted	

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
f. Deleted	
g. Reactor Enclosure Manual Initiation	N.A.
h. Refueling Area Manual Initiation	N.A.

TABLE NOTATIONS

(a) DELETED

3.3.2 (b) DELETED

* Isolation system instrumentation response time for MSIV only. No diesel generator delays assumed for MSIVs.

** DELETED

\# Isolation system instrumentation response time specified for the Trip Function actuating each valve group shall be added to the isolation time for the valves in each valve group to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.

\#\# With 45 second time delay.

\#\#\# Sensor is eliminated from response time testing for the MSIV actuation logic circuits. Response time testing and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required.

Amendment No. 6, 89, ~~112~~, ~~122~~, ~~146~~
OCT 1 3 2000

D01

PTS

~~TABLE 4.3.2.1-1~~

~~ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

See Table 3.3.2-1 for Changes

	~~TRIP FUNCTION~~	~~CHANNEL CHECK(a)~~	~~CHANNEL FUNCTIONAL TEST(a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
	1. MAIN STEAM LINE ISOLATION				
	a. Reactor Vessel Water Level				
	1) Low, Low, Level 2				1, 2, 3
	2) Low, Low, Low - Level 1				1, 2, 3
	b. DELETED				
	c. Main Steam Line Pressure - Low				1
4.3.1.1	d. Main Steam Line Flow - High				1, 2, 3
	e. Condenser Vacuum - Low				1, 2**, 3**
	f. Outboard MSIV Room Temperature - High				1, 2, 3
3.7.9	g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High				1, 2, 3
	~~h. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~
	2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
4.3.1.1	a. Reactor Vessel Water Level~~##~~ Low - Level 3				1, 2, 3
	b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High				1, 2, 3
	~~c. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~

D04 D06 D10 D04 D06

PTS

TS 3.3.1

See Table 3.3.2-1 for Changes

D01

~~TABLE 4.3.2.1-1 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

	~~TRIP~~ FUNCTION	~~CHANNEL CHECK(a)~~	~~CHANNEL FUNCTIONAL TEST(a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED	
	3. REACTOR WATER CLEANUP SYSTEM ISOLATION					
	a. RWCS Δ Flow - High				1, 2, 3	
	b. RWCS Area Temperature - High				1, 2, 3	D04
	c. RWCS Area Ventilation Δ Temperature - High				1, 2, 3	
4.3.1.1	d. SLCS Initiation	N.A.		N.A.	1, 2, 3	
	e. Reactor Vessel Water Level Low, Low, - Level 2				1, 2, 3	
	~~f. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~	D06
	4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION					
	a. HPCI Steam Line Δ Pressure - High				1, 2, 3	
	b. HPCI Steam Supply Pressure, Low				1, 2, 3	
	c. HPCI Turbine Exhaust Diaphragm Pressure - High				1, 2, 3	D04
4.3.1.1	d. HPCI Equipment Room Temperature - High				1, 2, 3	
	e. HPCI Equipment Room Δ Temperature - High				1, 2, 3	
	f. HPCI Pipe Routing Area Temperature - High				1, 2, 3	
	~~g. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~	D06
3.3.2	h. HPCI Steam Line Δ Pressure Timer	N.A.			1, 2, 3	

D01

See Table 3.3.2-1 for Changes

~~TABLE 4.3.2.1-1 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

PTS

~~TRIP~~ FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High				1, 2, 3
b. RCIC Steam Supply Pressure - Low				1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High				1, 2, 3
4.3.1.1 d. RCIC Equipment Room Temperature - High				1, 2, 3
e. RCIC Equipment Room Δ Temperature - High				1, 2, 3
f. RCIC Pipe Routing Area Temperature - High				1, 2, 3
~~g. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~
3.3.2 h. RCIC Steam Line Δ Pressure Timer	N.A.			1, 2, 3

D04

D06

D01

~~TABLE 4.3.2.1-1 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

See Table 3.3.2-1 for Changes

PTS

~~TRIP FUNCTION~~	~~CHANNEL CHECK(a)~~	~~CHANNEL FUNCTIONAL TEST(a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
6. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low - Level 2				1, 2, 3
4.3.1.1 2) Low, Low, Low - Level 1				1, 2, 3
b. Drywell Pressure## - High				1, 2, 3 D10
c. North Stack Effluent Radiation - High				1, 2, 3
d. ~~Deleted~~				D04
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High				1, 2, 3
f. ~~Deleted~~				
g. ~~Deleted~~				
h. Drywell Pressure - High/ Reactor Pressure - Low				1, 2, 3
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	~~N.A.~~			1, 2, 3
~~j. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~ D06

D01

~~TABLE 4.3.2.1-1~~ (Continued)

See Table 3.3.2-1 for Changes

PTS

~~ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

~~TRIP~~ FUNCTION	~~CHANNEL CHECK (a)~~	~~CHANNEL FUNCTIONAL TEST (a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
7. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level Low, Low - Level 2				1, 2, 3
b. Drywell Pressure## - High				1, 2, 3
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High				*#
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High				*#
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High				1, 2, 3
~~e. Deleted~~				
~~f. Deleted~~				
~~g. Reactor Enclosure Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~
~~h. Refueling Area Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~*~~

4.3.3.1

D09

D04

D06

~~(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.~~

D04

*Required when handling RECENTLY IRRADIATED FUEL in the secondary containment.

**When not administratively bypassed and/or when any turbine stop valve is open.

#During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

See Table 3.3.2-1 Changes

~~##These trip functions (2a, 6b, and 7b) are common to the RPS actuation trip function.~~

D09

PTS INSTRUMENTATION

~~3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~ D01

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. D02

3.3.2

APPLICABILITY: As shown in Table 3.3.~~3~~-1

1 D01

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.~~ D02

1

Actions a.2 and b.2

b. With one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.~~3~~-1. D01

~~c. With either ADS trip system subsystem inoperable, restore the inoperable trip system to OPERABLE status within:~~ D18

~~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.~~

Actions a.3 and b.3

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.~~ D04

~~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.~~

3.3.2

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 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.3-1~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~

D10

PTS Table 3.3.1-1 Function	~~TRIP~~ FUNCTION	MINIMUM OPERABLE CHANNELS ~~PER TRIP FUNCTION~~~~(a)~~	APPLICABLE OPERATIONAL CONDITIONS	ACTION	
	See Actions for Changes				
	1. CORE SPRAY SYSTEM~~***~~				
4.a	a. Reactor Vessel Water Level - Low Low Low, Level 1	3 ~~2/pump~~~~(b)~~	1, 2, 3	30	
8	b. Drywell Pressure - High	3 ~~2/pump~~~~(b)~~	1, 2, 3	30	D10
3.c	c. Reactor Vessel Pressure - Low (Permissive)	3 ~~6~~~~(b)~~	1, 2, 3	31	
	~~d. Manual Initiation~~	~~2(e)~~	~~1, 2, 3~~	~~33~~	D06
	2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM~~***~~				D10
4.a	a. Reactor Vessel Water Level - Low Low Low, Level 1	3 ~~2~~	1, 2, 3	30	
8	b. Drywell Pressure - High	3 ~~2~~	1, 2, 3	30	D18
3.c	c. Reactor Vessel Pressure - Low (Permissive)	~~2~~ 3	1, 2, 3	31	
12	d. Injection Valve Differential Pressure-Low (Permissive)	1/valve	1, 2, 3	31	
	~~e. Manual Initiation~~	~~1~~	~~1, 2, 3~~	~~33~~	D06
Note (o)	3. HIGH PRESSURE COOLANT INJECTION SYSTEM~~###~~ (o)				D10
4.b	a. Reactor Vessel Water Level - Low Low Level 2	3 ~~4~~	1, 2, 3	34	
8 Note (p)	b. Drywell Pressure - High~~####~~ (p)	3 ~~4~~	1, 2, 3	34	
10	c. Condensate Storage Tank Level - Low	~~2(c)~~ 3	1, 2, 3	35	
13	d. Suppression Pool Water Level - High	2	1, 2, 3	35	
4.c	e. Reactor Vessel Water Level - High, Level 8~~####~~	3 ~~4~~(d)	1, 2, 3	31	
	~~f. Manual Initiation~~	~~1/system~~	~~1, 2, 3~~	~~33~~	D06

PTS
Table 3.3.1-1
Function

TABLE 3.3.1-1 PLANT PROTECTION SYSTEM INSTRUMENTATION

D01

~~TABLE 3.3.3-1 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~

See Actions for Changes

LIMERICK - UNIT 1

PTS Table 3.3.1-1 Function	~~TRIP~~ FUNCTION	MINIMUM OPERABLE CHANNELS ~~PER TRIP FUNCTION~~ ~~(a)~~	APPLICABLE OPERATIONAL CONDITIONS	ACTION
Note (n)	4. AUTOMATIC DEPRESSURIZATION SYSTEM~~#***~~			
4.a	a. Reactor Vessel Water Level - Low Low Low, Level 1	~~2~~ 3	1, 2, 3	~~30~~
8	b. Drywell Pressure - High	~~2~~ 3	1, 2, 3	30
3.3.2	c. ADS Timer	1	1, 2, 3	31
11	d. Core Spray Pump Discharge Pressure - High (Permissive)	~~2~~ 6	1, 2, 3	~~31~~
11	e. RHR LPCI Mode Pump Discharge Pressure - High (Permissive)	~~4~~ 3	1, 2, 3	31
5.a	f. Reactor Vessel Water Level - Low, Level 3 (Permissive)	~~1~~	1, 2, 3	31
	~~g. Manual Initiation~~	~~2~~	~~1, 2, 3~~	~~33~~
3.3.2	h. ADS Drywell Pressure Bypass Timer	2	1, 2, 3	31

D10 D10 D17 D18 D10 D06

		TOTAL NO. OF CHANNELS(f)	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
	5. LOSS OF POWER					
3.3.5	1. 4.16 kV Emergency Bus Under-voltage (Loss of Voltage)	1/bus	1/bus	1/bus	1,2,3,4**,5**	36
	2. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	1/source/ bus	1/source/ bus	1/source/ bus	1,2,3,4**,5**	37

~~***The Minimum OPERABLE Channels Per Trip Function is per subsystem.~~

D10

PTS
Table 3.3.1-1
Notes

~~TABLE 3.3.3-1 (Continued)~~
~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~
~~TABLE NOTATIONS~~

D01

~~(a) 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 provided at least one OPERABLE channel in the same trip system is monitoring that parameter.~~ D04

~~(b) Also provides input to actuation logic for the associated emergency diesel generators.~~ D09

~~(c) One trip system. Provides signal to HPCI pump suction valves only.~~ D10

~~(d) On 1 out of 2 taken twice logic, provides a signal to trip the HPCI pump turbine only.~~

~~(e) The manual initiation push buttons start the respective core spray pump and diesel generator. The "A" and "B" logic manual push buttons also actuate an initiation permissive in the injection valve opening logic.~~ D09

3.3.5 (f) A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2.

~~* DELETED~~

Note (n) ~~#~~ Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

3.3.5 ** Required when ESF equipment is required to be OPERABLE.

Note (o) ~~##~~ Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

Note (p) ~~###~~ The injection function~~s~~ of Drywell Pressure - High ~~and Manual Initiation are~~ is not required to be OPERABLE with reactor steam dome pressure less than 550 psig. D06

PTS
3.3.1
Action

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

D01

~~ACTION 30 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:~~ D03

~~a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or in accordance with the Risk Informed Completion Time Program, or declare the associated system inoperable.~~

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

7 ~~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. D10

~~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 in accordance with the Risk Informed Completion Time Program*, or declare the associated ECCS inoperable.~~ D06

~~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 in accordance with the Risk Informed Completion Time Program, or declare the HPCI system inoperable.~~ D03

~~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~~ D03
8 ~~hours or in accordance with the Risk Informed Completion Time Program*, or~~ declare the HPCI system inoperable.

3.3.5 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.

~~*Not applicable when trip capability is not maintained.~~

PTS

D01

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

ACTION 37 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable device in the bypassed condition subject to the following conditions:

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable. 127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

3.3.5

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

PTS TS 3.3.1

LIMERICK - UNIT 1

D01

~~TABLE 3.3.3-2~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS~~

~~TRIP~~ FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE	
1. CORE SPRAY SYSTEM			D02
a. Reactor Vessel Water Level - Low Low Low, Level 1	~~≥ -129 inches*~~	≥ -136 inches	
b. Drywell Pressure - High	~~≤ 1.68 psig~~	≤ 1.88 psig	
c. Reactor Vessel Pressure - Low	~~≥ 455 psig,(decreasing)~~	≥ 435 psig, (decreasing)	D06
~~d. Manual Initiation~~	~~N.A.~~	~~N.A.~~	
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM			
a. Reactor Vessel Water Level - Low Low Low, Level 1	~~≥ -129 inches*~~	≥ -136 inches	D02
b. Drywell Pressure - High	~~≤ 1.68 psig~~	≤ 1.88 psig	
c. Reactor Vessel Pressure - Low	~~≥ 455 psig,(decreasing)~~	≥ 435 psig, (decreasing)	
d. Injection Valve Differential Pressure - Low	~~≥ 74 psid, (decreasing)~~	≥ 64 psid and ≤ 84 psid	D06
~~e. Manual Initiation~~	~~N.A.~~	~~N.A.~~	
3. HIGH PRESSURE COOLANT INJECTION SYSTEM			
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -38 inches*	≥ -45 inches	D02
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig	
c. Condensate Storage Tank Level - Low	≥ 167.8 inches**	≥ 164.3 inches	
d. Suppression Pool Water Level - High	≤ 24 feet 1.5 inches	≤ 24 feet 3 inches	
e. Reactor Vessel Water Level - High, Level 8	≤ 54 inches	≤ 60 inches	D06
~~f. Manual Initiation~~	~~N.A.~~	~~N.A.~~	
4. AUTOMATIC DEPRESSURIZATION SYSTEM			
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches	D02
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig	
3.3.2 c. ADS Timer	≤ 105 seconds	≤ 117 seconds	
d. Core Spray Pump Discharge Pressure - High	≥ 145 psig,(increasing)	≥ 125 psig, (increasing),	D02
e. RHR LPCI Mode Pump Discharge Pressure-High	≥ 125 psig,(increasing)	≥ 115 psig, (increasing)	
f. Reactor Vessel Water Level-Low, Level 3	≥ 12.5 inches	≥ 11.0 inches	
~~g. Manual Initiation~~	~~N.A.~~	~~N.A.~~	D06
3.3.2 h. ADS Drywell Pressure Bypass Timer	≤ 420 seconds	≤ 450 seconds	

~~*See Bases Figure B 3/4.3-1.~~

~~**Corresponds to 2.3 feet indicated.~~ D09

~~TABLE 3.3.3-2 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS~~

TRIP FUNCTION		TRIP SETPOINT	ALLOWABLE VALUE
5. LOSS OF POWER	RELAY		
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X	NA	NA
b. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	RELAY		
	127-11X0X and 102-11X0X	a. 4.16 kV Basis 2905 ± 115 volts	2905 ± 145 volts
		b. 120 V Basis 83 ± 3 volts	83 ± 4 volts
		c. < 1 second time delay	< 1.5 second time delay
	127Y-11X0X** and 127Y-1-11X0X	a. 4.16 kV Basis 3640 ± 91 volts	3640 ± 182 volts
		b. 120 V Basis 104 ± 3 volts	104 ± 5.2 volts
		c. < 52 second time delay	< 60 second time delay
	127Z-11X0X and 162Y-11X0X	a. 4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b. 120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c. < 10 second time delay	< 11 second time delay
	127Z-11X0X and 162Z-11X0X	a. 4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b. 120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c. < 61 second time delay	< 64 second time delay

3.3.5

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

PTS

TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES

ECCS		RESPONSE TIME (Seconds)
1.	CORE SPRAY SYSTEM	≤ 27#
2.	LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM	≤ 40#
3.	AUTOMATIC DEPRESSURIZATION SYSTEM	N.A.
4.	HIGH PRESSURE COOLANT INJECTION SYSTEM	≤ 60#
5.	LOSS OF POWER	N.A.

3.3.2 3.3.5

3.3.2 # ECCS actuation instrumentation is eliminated from response time testing.

D01

~~TABLE 4.3.3.1-1~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

See CTS Table 3.3.1-1 for Changes

PTS

	~~TRIP FUNCTION~~	~~CHANNEL CHECK(a)~~	~~CHANNEL FUNCTIONAL TEST(a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED	
	1. CORE SPRAY SYSTEM					D04
	a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3	
4.3.1.1	b. Drywell Pressure - High				1, 2, 3	
	c. Reactor Vessel Pressure - Low				1, 2, 3	
	~~d. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~	D06
	2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM					
	a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3	
4.3.1.1	b. Drywell Pressure - High				1, 2, 3	
	c. Reactor Vessel Pressure - Low				1, 2, 3	D04
	d. Injection Valve Differential Pressure - Low (Permissive)				1, 2, 3	
	~~e. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~	D06
Table 3.3.1-1 Note (o)	3. HIGH PRESSURE COOLANT INJECTION SYSTEM***					
	a. Reactor Vessel Water Level - Low Low, Level 2				1, 2, 3	
	b. Drywell Pressure - High				1, 2, 3	
	c. Condensate Storage Tank Level - Low				1, 2, 3	
4.3.1.1	d. Suppression Pool Water Level - High				1, 2, 3	D04
	e. Reactor Vessel Water Level - High, Level 8				1, 2, 3	
	~~f. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~	D06

D01

See CTS Table 3.3.1-1 for Changes

PTS

~~TABLE 4.3.3.1-1 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

	~~TRIP FUNCTION~~	~~CHANNEL CHECK(a)~~	~~CHANNEL FUNCTIONAL TEST(a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
Table 3.3.1-1 Note (n)	4. AUTOMATIC DEPRESSURIZATION SYSTEM#				
4.3.1.1	a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3
	b. Drywell Pressure - High				1, 2, 3
3.3.2	c. ADS Timer	N.A.			1, 2, 3
	d. Core Spray Pump Discharge Pressure - High				1, 2, 3
	e. RHR LPCI Mode Pump Discharge Pressure - High				1, 2, 3
	f. Reactor Vessel Water Level - Low, Level 3				1, 2, 3
	~~g. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~
3.3.2	h. ADS Drywell Pressure Bypass Timer	N.A.			1, 2, 3
	5. LOSS OF POWER				
3.3.5	a. 4.16 kV Emergency Bus Under-voltage (Loss of Voltage)##	N.A.		N.A.	1, 2, 3, 4**, 5**
	b. 4.16 kV Emergency Bus Under - voltage (Degraded Voltage)				1, 2, 3, 4**, 5**

D04

D04

D06

D04

~~(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.~~

~~* DELETED~~

3.3.5 ** Required OPERABLE when ESF equipment is required to be OPERABLE.

Note (o) *** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

Note (n) # Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

3.3.5 ## Loss of Voltage Relay 127-11X is not field setable.

PTS

INSTRUMENTATION

~~END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION~~ D01

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. D02

3.3.4.2

Table 3.3.1-1 Note (h)

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

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.~~ D02

3.3.1 Action a.1.

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 ~~or in accordance with the Risk Informed Completion Time Program*~~. D03

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:~~ D03

Action 11

~~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 or in accordance with the Risk Informed Completion Time Program.~~

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

3.3.4.2

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 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.

~~*Not applicable when trip capability is not maintained~~. D03

PTS

D04

INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

4.3.1.1 ~~4.3.4.2.1 Each of the required end-of-cycle recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST, including trip system logic testing, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.~~

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

4.3.4.2.3 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each trip function shown in Table 3.3.4.2-3 shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit.

4.3.4.2.4 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured in accordance with the Surveillance Frequency Control Program.

~~TABLE 3.3.4.2-1~~

~~END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION~~

D01

TABLE 3.3.1-1`
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D10

PTS

~~TRIP~~ FUNCTION		MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM*~~
20	1. Turbine Stop Valve - Closure	3 ~~2**~~
21	2. Turbine Control Valve-Fast Closure	3 ~~2**~~

~~* A trip system may be placed in an inoperable status for up to 6 hours for required surveillance provided that the other trip system is OPERABLE.~~

Table 3.3.1-1 Applicability Functions 21 & 22

** This function shall be automatically bypassed when turbine first stage pressure is equivalent to THERMAL POWER LESS than 29.5% of RATED THERMAL POWER.

TABLE 3.3.1-1`
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

~~TABLE 3.3.4.2-2~~

~~END-OF-CYCLE RECIRCULATION PUMP TRIP SETPOINTS~~

D01

~~TRIP~~ FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE
1. Turbine Stop Valve-Closure	~~≤ 5% closed~~	≤ 7% closed
2. Turbine Control Valve-Fast Closure	~~≥ 500 psig~~	≥ 465 psig

D02

PTS

3.3.4.2

TABLE 3.3.4.2-3

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Milliseconds)
1. Turbine Stop Valve-Closure	$\leq$ 175
2. Turbine Control Valve-Fast Closure	$\leq$ 175

~~INFORMATION ON THIS PAGE HAS BEEN DELETED~~

PTS

INSTRUMENTATION

~~3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION~~ D01

LIMITING CONDITION FOR OPERATION

~~3.3.5 The reactor core isolation cooling (RCIC) system actuation~~
3.3.1 ~~instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE with their~~ D02
~~trip setpoints set consistent with the values shown in the Trip Setpoint~~
~~column of Table 3.3.5-2.~~

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

ACTION:

~~a. With a RCIC system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.5-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.~~ D02

3.3.1 Action a.1 and b.1

b. With one or more RCIC system actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.5-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1 ~~4.3.5.1 Each of the required RCIC 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. CHANNEL CHECK and CHANNEL CALIBRATION are not required for manual initiation.~~ D04

~~4.3.5.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.~~

TABLE 3.3.1-1`
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

~~TABLE 3.3.5-1~~

~~REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION~~

D01

PTS Table 3.3.1-1 Function	~~FUNCTIONAL UNITS~~	MINIMUM OPERABLE CHANNELS ~~PER TRIP FUNCTION*~~	ACTION
4.b	a. Reactor Vessel Water Level - Low Low, Level 2	3 ~~4#~~	50
4.c	b. Reactor Vessel Water Level - High, Level 8	3 ~~4#~~	~~51~~
10	c. Condensate Storage Tank Water Level - Low	3 ~~2**~~	52
	~~d. Manual Initiation##~~	~~1/system***~~	~~53~~

See Actions for Changes

D10 D17 D06

~~*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 provided all other channels monitoring that parameter are OPERABLE.~~ D04

~~**One trip system with one-out-of-two logic.~~ D10

~~***One trip system with one channel.~~ D06

~~#One trip system with one-out-of-two twice logic.~~ D10

~~##The injection function of Manual Initiation is not required to be OPERABLE with reactor steam dome pressure less than 550 psig.~~ D06

~~TABLE 3.3.5-1 (Continued)~~

D01

~~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:~~ D03

~~a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or in accordance with the Risk Informed Completion Time Program, 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.~~ D17

~~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 in accordance with the Risk Informed Completion Time Program,* or declare the RCIC system inoperable.~~ D03

~~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.~~ D06

~~*Not applicable when trip capability is not maintained.~~

TABLE 3.3.1-1`
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.5-2~~

~~REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS~~

~~FUNCTIONAL UNITS~~	~~TRIP SETPOINT~~	ALLOWABLE VALUE
a. Reactor Vessel Water Level - Low Low, Level 2	~~≥-38 inches*~~	≥-45 inches
b. Reactor Vessel Water Level - High, Level 8	~~≤ 54 inches~~	≤ 60 inches
c. Condensate Storage Tank Level - Low	~~≥ 135.8** inches~~	≥ 132.3 inches
~~d. Manual Initiation~~	~~N.A.~~	~~N.A.~~

D02

D06

~~*See Bases Figure B 3/4.3-1.~~

~~**Corresponds to 2.3 feet indicated.~~

D09

Unit 2

Current Technical Specifications Markup

3.3.2

PTS

3/4.3 INSTRUMENTATION

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

3/4.3.1 ~~REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

D01

LIMITING CONDITION FOR OPERATION

The plant protection system

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

3.3.2 TIME as shown in Table 3.3.1-2.

APPLICABILITY: As shown in Table 3.3.1-1.

D05

ACTION:

Function

Note: Separate condition entry is allowed for each ~~channel~~.

Table 3.3.1-1 Note (b)

~~Note:~~ When Functional Unit 2.b and 2.c channels are inoperable due the calculated power exceeding the APRM output by more than 2% of RATED THERMAL POWER while operating at ≥ 25% of RATED THERMAL POWER, entry into the associated Actions may be delayed up to 2 hours.

Insert 1

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

D03

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

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

~~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.~~

---

* 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.

D03

** 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.

Specification 3/4.3.1

Insert 1

a. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions one less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 12 hours:

   1. Place the required inoperable channel in the tripped condition#, or

   2. Initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

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

b. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions two or more less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 6 hours:

   1. Place the required inoperable channels in the tripped condition#, or

   2. Place one required inoperable channel in the trip condition# and initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

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

c. In OPERATIONAL CONDITION 4, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour verify all insertable control rods to be inserted in the core* and lock the reactor mode switch in the Shutdown position within 1 hour.

d. In OPERATIONAL CONDITION 5, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour place the inoperable channels in the tripped condition, or within 1 hour suspend all operations involving CORE ALTERATIONS and insert all insertable control rods*.

----

* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

For permissive Functions 3.c.2, 4.c, 11, and 12, Actions a.1 and b.1 are not applicable. For these functional units inoperable channel(s) shall be placed in bypass instead of trip to comply with Action b.2.

PTS

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

3/4.3 INSTRUMENTATION

3/4.3.1 ~~REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

SURVEILLANCE REQUIREMENTS

Insert 2

~~4.3.1.1 Each reactor protection system 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 4.3.1.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.1.1-1.~~ D04

~~4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program, except Table 4.3.1.1-1 Functions 2.a, 2.b, 2.c, 2.d, 2.e, and 2.f. Functions 2.a, 2.b, 2.c, 2.d, and 2.f do not require separate LOGIC SYSTEM FUNCTIONAL TESTS. For Function 2.e, tests shall be performed in accordance with the Surveillance Frequency Control Program. LOGIC SYSTEM FUNCTIONAL TEST for Function 2.e includes simulating APRM and OPRM trip conditions at the APRM channel inputs to the voter channel to check all combinations of two tripped inputs to the 2-Out-Of-4 voter logic in the voter channels.~~

3.3.2 4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its 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 reactor trip system.

Specification 3/4.3.1

Insert 2
Page 1

4.3.1.1 Each plant protection system instrumentation channel except for Function 1, "Intermediate Range Monitors," and Function 2, "Average Power Range Monitors," shall be demonstrated OPERABLE by the performance of a SENSOR CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.2 The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.

4.3.1.3 Each IRM Neutron Flux - High channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCITONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Neutron detectors may be excluded from CHANNEL CALIBRATION.

4.3.1.4 Each IRM Inoperative channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.5 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale, Neutron Flux - Upscale, 2-Out-Of-4 Voter, and OPRM Upscale function shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.6 Each APRM Neutron Flux - Upscale (Setdown)*, Simulated Thermal Power - Upscale**, Neutron Flux - Upscale, Inoperative, 2-Out-Of-4 Voter, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.7 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale***, Neutron Flux - Upscale***, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Calibration includes verification that the OPRM Upscale trip auto-enable (not-bypass) setpoint for APRM Simulated Thermal Power is ≥ 29.5% and for recirculation drive flow is < 60%.

4.3.1.8 The APRM LPRM inputs shall be calibrated at least once per 2000 effective full power hours (EFPH).

Insert 2
Page 2

4.3.1.9 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of the Turbine Stop Valve - Closure and the Turbine Control Valve - Fast Closure End-of-Cycle Recirculation Pump Trip System Functions shall be performed in accordance with the Surveillance Frequency Control Program.

----

* Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

** The CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.

*** Calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED THERMAL POWER. Verify the calculated power does not exceed the APRM channels by greater than 2% of RATED THERMAL POWER.

D01

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE 1-1

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

PTS

Table 3.3.1-1 Function

	~~FUNCTIONAL UNIT~~	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (a)~~ (D10)	ACTION (See Actions for Changes)
1	1. Intermediate Range Monitors~~(b)~~ (a):			
	a. Neutron Flux - High	2 3~~(i)~~, 4~~(i)~~ (f) 5~~(i)~~ (f)	6 ~~3~~ ~~3~~ ~~3(d)~~ (D07)	1 2 3
	b. Inoperative	2 3~~(i)~~, 4~~(i)~~ (f) 5~~(i)~~ (f)	6 ~~3~~ ~~3~~ ~~3(d)~~	1 2 3
2	2. Average Power Range Monitor~~(c)~~ (b):			
	a. Neutron Flux - Upscale (Setdown)	2	~~3(m)~~	1
	b. Simulated Thermal Power - Upscale	1	~~3(m)~~ (D08)	4
	c. Neutron Flux - Upscale	1	~~3(m)~~ (D14)	4
	d. Inoperative	1, 2	~~3(m)~~	1
	e. 2-Out-Of-4 Voter	1, 2	4 ~~2~~	1
	f. OPRM Upscale	~~1(o)(p)~~ (c) (d)	~~3(m)~~	10
3.A	3. Reactor Vessel Steam Dome Pressure - High	1, ~~2(f)~~ (k) 1	3 ~~2~~	1
5	4. Reactor Vessel Water Level - Low, Level 3	1, 2, 3 (D11)	3 ~~2~~ (D10)	1
19	5. Main Steam Line Isolation Valve-Closure	1(g)	3 ~~1/valve~~	4

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE 3.3.1-1 (Continued)

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

D01

PTS

D10

Table 3.3.1-1 Function	~~FUNCTIONAL UNIT~~	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (a)~~	ACTION
	6. ~~DELETED~~	~~DELETED~~	~~DELETED~~	~~DELETED~~
8	7. Drywell Pressure - High	1, 2~~(h)~~ (s)	~~2~~	1
6	8. Scram Discharge Volume Water Level - High			
	a. Level Transmitter	1, 2 5~~(i)~~	3 ~~2~~ 3 ~~2~~	1 3
	b. Float Switch	1, 2 5~~(i)~~ (f)	3 ~~2~~ 3 ~~2~~	1 3
20	9. Turbine Stop Valve - Closure	1~~(j)~~	3 ~~4~~(k)	6
21	10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	1~~(j)~~ (h)	3 ~~2~~(k)	6
7	11. Reactor Mode Switch Shutdown Position	1, 2 3, 4 5	~~2~~ 3 ~~2~~ ~~2~~	1 7 3
	~~12. Manual Scram~~	~~1, 2~~ ~~3, 4~~ ~~5~~	~~2~~ ~~2~~ ~~2~~	~~1~~ ~~8~~ ~~9~~

D10

D09

D06

See Actions for Changes

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE 3.3.1-1 (Continued)

PTS ~~REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

3.3.1 Actions

ACTION STATEMENTS

a.1 and b.1 ~~ACTION 1~~ - Be in at least HOT SHUTDOWN within 12 hours.

c, 2 ~~ACTION 2~~ - Verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within 1 hour.

d, 16 ~~ACTION 3~~ - Suspend all operations involving CORE ALTERATIONS and insert all insertable control rods within 1 hour.

14 ~~ACTION 4~~ - Be in at least STARTUP within 6 hours.

~~ACTION 5~~ - ~~Be in STARTUP with the main steam line isolation valves closed within 6 hours or in at least HOT SHUTDOWN within 12 hours.~~

Not referenced in Table 3.3.1-1

1 ~~ACTION 6~~ - Initiate a reduction in THERMAL POWER within 15 minutes and reduce turbine first stage pressure until the function is automatically bypassed, within 2 hours.

15 ~~ACTION 7~~ - Verify all insertable control rods to be inserted within 1 hour.

~~ACTION 8~~ - ~~Lock the reactor mode switch in the Shutdown position within 1 hour.~~ D06

~~ACTION 9~~ - ~~Suspend all operations involving CORE ALTERATIONS, and insert all insertable control rods and lock the reactor mode switch in the Shutdown position within 1 hour.~~ D06

3.3.1 Action d. ~~ACTION 10~~ - a. If the condition exists due to a common-mode OPRM deficiency*, then initiate alternate method to detect and suppress thermal-hydraulic instability oscillations within 12 hours AND restore required channels to OPERABLE status within 120 days,

OR

b. Reduce THERMAL POWER to < 25% RATED THERMAL POWER within 4 hours.

~~* Unanticipated characteristic of the instability detection algorithm or equipment that renders all OPRM channels inoperable at once.~~ D09

PTS

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

D01

TABLE 3.3.1-1 (Continued)

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

TABLE NOTATIONS

(r) ~~(a)~~ 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 provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

(a) ~~(b)~~ This function shall automatically be bypassed when the reactor mode switch is in the Run position.

~~(c)~~ ~~DELETED~~

~~(d)~~ ~~The noncoincident NMS reactor trip function logic is such that all channels go to both trip systems. Therefore, when the "shorting links" are removed, the Minimum OPERABLE Channels Per Trip System is 6 IRMs.~~ D07

(b) ~~(e)~~ An APRM channel is inoperable if there are less than 3 LPRM inputs per level or less than 20 LPRM inputs to an APRM channel, or if more than 9 LPRM inputs to the APRM channel have been bypassed since the last APRM calibration (weekly gain calibration).

(k) ~~(f)~~ This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(g) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(s) ~~(h)~~ This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(f) ~~(i)~~ With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(h) ~~(j)~~ This function shall be automatically bypassed when turbine first stage pressure is equivalent to a THERMAL POWER of less than 29.5% of RATED THERMAL POWER.

~~(k)~~ ~~Also actuates the EOC-RPT system.~~ D09

~~(l)~~ ~~DELETED~~

~~(m)~~ ~~Each APRM channel provides inputs to both trip systems.~~ D08

~~(n)~~ ~~DELETED~~

(c) ~~(o)~~ With THERMAL POWER ≥ 25% RATED THERMAL POWER. The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60%. The OPRM trip output may be automatically bypassed when APRM Simulated Thermal Power is < 29.5% or recirculation drive flow is ≥ 60%.

(d) ~~(p)~~ A minimum of 23 cells, each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for an OPRM channel to be OPERABLE.

TA .3.1-2

REACTOR PROTECTION SYSTEM RESPONSE TIMES

3.3.2

FUNCTIONAL UNIT	RESPONSE TIME (Seconds)
1. Intermediate Range Monitors:	
a. Neutron Flux - High	N.A.
b. Inoperative	N.A.
2. Average Power Range Monitor*:	
a. Neutron Flux - Upscale (Setdown)	N.A.
b. Simulated Thermal Power - Upscale	N.A.
c. Neutron Flux - Upscale	N.A.
d. Inoperative	N.A.
e. 2-Out-Of-4 Voter	≤0.05*
f. OPRM Upscale	N.A.
3. Reactor Vessel Steam Dome Pressure - High	≤0.55
4. Reactor Vessel Water Level - Low, Level 3	≤1.05#
5. Main Steam Line Isolation Valve - Closure	≤0.06
6. DELETED	DELETED
7. Drywell Pressure - High	N.A.
8. Scram Discharge Volume Water Level - High	
a. Level Transmitter	N.A.
b. Float Switch	N.A.
9. Turbine Stop Valve - Closure	≤0.06
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≤0.08**
11. Reactor Mode Switch Shutdown Position	N.A.
12. Manual Scram	N.A.

* Neutron detectors, APRM channel and 2-Out-Of-4 Voter channel digital electronics are exempt from response time testing. Response time shall be measured from activation of the 2-Out-Of-4 Voter output relay. For application of Specification 4.3.1.3, the redundant outputs from each 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8. Testing of OPRM and APRM outputs shall alternate.

** Measured from start of turbine control valve fast closure.

\# Sensor is eliminated from response time testing for the RPS circuits. Response time testing and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required.

~~TABLE 4.3.1.1-1~~

D01

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

D04

See changes to Table 3.3.1-1

PTS	~~FUNCTIONAL UNIT~~	CHANNEL CHECK (n)	CHANNEL FUNCTIONAL TEST (n)	CHANNEL CALIBRATION(a)~~(n)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
4.3.1.2 4.3.1.3	1. Intermediate Range Monitors: a. Neutron Flux - High	(b)	~~(j)~~		2 3(i), 4(i), 5(i)
4.3.1.4	b. Inoperative	N.A.	~~(j)~~	N.A.	2, 3(i), 4(i), 5(i)
	2. Average Power Range Monitor(f): a. Neutron Flux - Upscale (Setdown)	(b)	~~(l)~~ *		2
4.3.1.5, 4.3.1.6, 4.3.1.7, 4.3.1.8, 4.3.1.9,	b. Simulated Thermal Power - Upscale		(e)	(d), ~~(g)~~, ~~(o), (p)~~	1
	c. Neutron Flux - Upscale			(d)	1
	d. Inoperative	N.A.		N.A.	1, 2
	e. 2-Out-Of-4 Voter			N.A.	1, 2
	f. OPRM Upscale		(e)	(c)~~(g)~~	1(m)
4.3.1.1	3. Reactor Vessel Steam Dome Pressure - High				~~1, 2(h)~~
4.3.1.1	4. Reactor Vessel Water Level - Low, Level 3				~~1, 2~~
4.3.1.1	5. Main Steam Line Isolation Valve - Closure	~~N.A.~~			~~1~~
	~~6.~~ ~~DELETED~~				
4.3.1.1	7. Drywell Pressure - High				~~1, 2~~
4.3.1.1	8. Scram Discharge Volume Water Level - High a. Level Transmitter				~~1, 2, 5(i)~~
	b. Float Switch	~~N.A.~~			~~1, 2, 5(i)~~

D07

D13

D12

D13

D04

PTS

D01

~~TABLE 4.3.1.1-1 (Continued)~~

SR or Table 4.3.1-1 Note

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

See changes to Table 3.3.1-1

D04

	~~FUNCTIONAL UNIT~~	CHANNEL CHECK ~~(n)~~	CHANNEL FUNCTIONAL TEST ~~(n)~~	CHANNEL CALIBRATION(a)~~(n)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
4.3.1.1	9. Turbine Stop Valve - Closure	~~N.A.~~			1
4.3.1.1	10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	~~N.A.~~			1
4.3.1.1	11. Reactor Mode Switch Shutdown Position	~~N.A.~~		~~N.A.~~	~~1, 2, 3, 4, 5~~
	~~12. Manual Scram~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3, 4, 5~~

D04

D06

Moved to SENSOR CHANNEL CALIBRATION definition.

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

4.3.1.2 (b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for a least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.

4.3.1.7 (c) Calibration includes verification that the OPRM Upscale trip auto-enable (not-bypass) setpoint for APRM Simulated Thermal Power is ≥ 29.5% and for recirculation drive flow is < 60%.

*** (d) The ~~more frequent~~ calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥ 25% of RATED THERMAL POWER. Verify the calculated power does not exceed the APRM channels by greater than 2% of RATED THERMAL POWER.

4.3.1.8 (e) CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.

(f) The LPRMs shall be calibrated at least once per 2000 effective full power hours (EFPH).

~~(g) The less frequent calibration includes the flow input function.~~

D13

Note (k) ~~(h)~~ This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

Note (f) ~~(i)~~ With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

~~(j) If the RPS shorting links are required to be removed per Specification 3.9.2, they may be reinstalled for up to 2 hours for required surveillance. During this time, CORE ALTERATIONS shall be suspended, and no control rod shall be moved from its existing position.~~

D07

~~(k) DELETED~~

Note* ~~(l)~~ Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

~~(m) With THERMAL POWER ≥ 25% of RATED THERMAL POWER.~~

~~(n) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.~~

D04

~~TABLE 4.3.1.1-1 (Continued)~~

D01

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

D12

~~(o) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.~~

~~(p) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Trip Setpoint at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the Trip Setpoint are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the surveillance procedures (field setting) to confirm channel performance. The methodologies used to determine the as-found and the as-left tolerances are specified in the associated Technical Specifications Bases.~~

SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

2.2.1 2.2.1 The reactor protection system instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2.1-1.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

~~With a reactor protection system instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2.1-1, declare the channel inoperable* and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its setpoint adjusted consistent with the Trip Setpoint value.~~ D02

Table 3.3.1-1 Notation (e). *The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

PTS

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

~~TABLE 2.2.1-1~~

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS~~

~~FUNCTIONAL UNIT~~	~~TRIP SETPOINT~~	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ ~~120/125 divisions of full scale~~	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-Upscale (Setdown)	≤ ~~15.0% of RATED THERMAL POWER~~	≤ 20.0% of RATED THERMAL POWER
b. Simulated Thermal Power - Upscale:		
- Two Recirculation Loop Operation	≤ ~~0.65 W + 61.7% and~~ ≤ ~~116.6% of RATED THERMAL POWER~~	≤ 0.65 W + 62.2% and ≤ 117.0% of RATED THERMAL POWER
- Single Recirculation Loop Operation***	≤ ~~0.65 (W-7.6%) + 61.5% and~~ ≤ ~~116.6% of RATED THERMAL POWER~~	≤ 0.65 (W-7.6%) + 62.0% and ≤ 117.0% of RATED THERMAL POWER
c. Neutron Flux - Upscale	~~118.3% of RATED THERMAL POWER~~	118.7% of RATED THERMAL POWER
d. Inoperative	~~N.A.~~	N.A.
e. 2-Out-Of-4 Voter	~~N.A.~~	N.A.
f. OPRM Upscale	~~****~~	N.A.
3. Reactor Vessel Steam Dome Pressure - High	≤ ~~1096~~ ps~~ig~~	≤ 1103 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ ~~12.5 inches above instrument zero*~~	≥ 11.0 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	≤ ~~8% closed~~	≤ 12% closed
~~6.~~ ~~DELETED~~	~~DELETED~~	~~DELETED~~
7. Drywell Pressure - High	≤ ~~1.68 psig~~	≤ 1.88 psig
8. Scram Discharge Volume Water Level - High		
a. Level Transmitter	≤ ~~261' 1 1/4" elevation**~~	≤ 261' 9 1/4" elevation
b. Float Switch	≤ ~~261' 1 1/4" elevation**~~	≤ 261' 9 1/4" elevation

D02

~~* See Bases Figure B 3/4.3-1.~~
~~** Equivalent to 25.58 gallons/scram discharge volume.~~
~~***~~ The 7.6% flow "offset" for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero.
~~**** See COLR for OPRM period based detection algorithm trip setpoints.~~ OPRM Upscale trip output auto-enable (not bypassed) setpoints shall be APRM Simulated Thermal Power ≥ 29.5% and recirculation drive flow < 60%.

D09
D02

Table 3.3.1-1 Note (e)

Table 3.3.1-1 Note (c)

D01

PTS

~~TABLE 2.2.1-1 (Continued)~~

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

~~REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS~~

FUNCTION~~AL UNIT~~	~~TRIP SETPOINT~~	ALLOWABLE VALUES
9. Turbine Stop Valve - Closure	~~≤ 5% closed~~	≤ 7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	~~≥ 500 psig~~	≥ 465 psig
11. Reactor Mode Switch Shutdown Position	~~N.A.~~	N.A.
~~12. Manual Scram~~	~~N.A.~~	~~N.A.~~

D02

D06

INSTRUMENTATION

D01

~~3/4.3.2. ISOLATION ACTUATION INSTRUMENTATION~~

LIMITING CONDITION FOR OPERATION

3.3.1 ~~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~~ D02

3.3.2 ~~Setpoint column of Table 3.3.2.-2 and~~ with ISOLATION SYSTEM RESPONSE TIME as shown in Table 3.3.2-3. D01

APPLICABILITY: As shown in Table 3.3.~~2~~-1.

1

ACTION:

D02

~~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.~~

D03

~~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.~~

D03

~~* Trip functions common to RPS Actuation Instrumentation are shown in Table 4.3.2.1-1.~~
~~** Not applicable when trip capability is not maintained.~~
~~# Not applicable for Function 7, Secondary Containment Isolation.~~

PTS

INSTRUMENTATION

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

~~c. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within 1 hour and take the ACTION required by Table 3.3.2-1.~~ D03

SURVEILLANCE REQUIREMENTS

~~4.3.2.1 Each isolation 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 4.3.2.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.2.1-1.~~

~~4.3.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operations of all channels shall be performed in accordance with the Surveillance Frequency Control Program.~~ D04

3.3.2 4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shown in Table 3.3.2-3 shall be demonstrated to be within its 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 accordance with the Surveillance Frequency Control Program, where N is the total number of redundant channels in a specific isolation trip system.

~~** The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition; if both systems have the same number of inoperable channels, place either trip system in the tripped condition.~~ D03

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.2-1~~

~~ISOLATION ACTUATION INSTRUMENTATION~~

D10

PTS Table 3.3.1-1 Function	~~TRIP FUNCTION~~	~~ISOLATION SIGNAL (a)~~	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (b)~~	APPLICABLE OPERATIONAL CONDITION	ACTION
	1. MAIN STEAM LINE ISOLATION				
	a. Reactor Vessel Water Level				
4.b	1) Low, Low-Level 2	~~B~~	3 ~~2~~	1, 2, 3	21
4.a	2) Low, Low, Low-Level 1	~~C~~	3 ~~2~~	1, 2, 3	21
	~~b.~~ ~~DELETED~~	~~DELETED~~	~~DELETED~~	~~DELETED~~	~~DELETED~~
22	c. Main Steam Line Pressure - Low	~~P~~	3 ~~2~~	1	22
23	d. Main Steam Line Flow - High	~~E~~	3/steam line ~~2/line~~	1, 2, 3	20
24	e. Condenser Vacuum - Low	~~Q~~	3 ~~2~~	1, ~~2**~~, ~~3**~~ (i)	21
25	f. Outboard MSIV Room Temperature - High	F~~(f)~~ (l)	3 ~~2~~	1, 2, 3	21
3.7.9	g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	F(f)	14	1, 2, 3	21
	~~h. Manual Initiation~~	~~NA~~	~~2~~	~~1, 2, 3~~	~~24~~
	2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
5.a	a. Reactor Vessel Water Level Low - Level 3 -SDC	~~A~~	3 ~~2~~	1, 2, 3	23
3.b	b. Reactor Vessel (RHR Cut-In ~~Permissive~~) Pressure - High	~~V~~	3 ~~2~~	1, 2, 3	23
	c. ~~Manual Initiation~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~24~~

See Actions for Changes

D09

D10

D09

D06

D09

D17

D06

D10

LIMERICK - UNIT 2

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS
D01

~~TABLE 3.3.2-1 (Continued)~~
~~ISOLATION ACTUATION INSTRUMENTATION~~

Table 3.3.1-1
Function

		~~TRIP~~ FUNCTION	~~ISOLATION SIGNAL (a)~~	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (b)~~	APPLICABLE OPERATIONAL CONDITION	ACTION
	3.	REACTOR WATER CLEANUP SYSTEM ISOLATION				
26	a.	RWCS Δ Flow - High	~~J~~	2 ~~1~~	1, 2, 3	23
27	b.	RWCS Area Temperature - High	~~J~~	12 ~~6~~	1, 2, 3	23
28	c.	RWCS Area Ventilation Δ Temperature - High	~~J~~	12 ~~6~~	1, 2, 3	23
29	d.	SLCS Initiation	~~Y(d)~~	NA	1, 2, 3	23
4.b	e.	Reactor Vessel Water Level - Low, Low - Level 2	~~B~~	3 ~~2~~	1, 2, 3	23
	~~f.~~	~~Manual Initiation~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~24~~
	4.	HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
14	a.	HPCI Steam Line Δ Pressure - High	~~L~~	2 1	1, 2, 3	23
3.d	b.	HPCI Steam Supply Pressure - Low	~~LA~~	3 2	1, 2, 3	23
15	c.	HPCI Turbine Exhaust Diaphragm Pressure - High	~~L~~	3 2	1, 2, 3	23
16	d.	HPCI Equipment Room Temperature - High	~~L~~	2 1	1, 2, 3	23
17	e.	HPCI Equipment Room Δ Temperature - High	~~L~~	2 1	1, 2, 3	23

D10 D09 D10 D15 D10 D06 D09 D10

See Actions for Changes

PTS

Table 3.3.1-1
Function

LIMERICK - UNIT 2

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

~~TABLE 3.3.2-1 (Continued)~~
~~ISOLATION ACTUATION INSTRUMENTATION~~

D01

	~~TRIP~~ FUNCTION	~~ISOLATION SIGNAL (a)~~	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
	4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION (Continued)				
18	f. HPCI Pipe Routing Area Temperature - High	~~L~~	2 ~~4~~	1, 2, 3	23
	~~g. Manual Initiation~~	~~NA(e)~~	~~1/system~~	~~1, 2, 3~~	~~24~~
3.3.2	h. HPCI Steam Line Δ Press Timer	NA	1	1, 2, 3	23
	5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
30	a. RCIC Steam Line Δ Pressure - High	~~K~~	2 ~~1~~	1, 2, 3	23
3.e	b. RCIC Steam Supply Pressure - Low	~~KA~~	3 ~~2~~	1, 2, 3	23
31	c. RCIC Turbine Exhaust Diaphragm Pressure - High	~~K~~	3 ~~2~~	1, 2, 3	23
32	d. RCIC Equipment Room Temperature - High	~~K~~	2 ~~1~~	1, 2, 3	23
33	e. RCIC Equipment Room Δ Temperature - High	~~K~~	2 ~~1~~	1, 2, 3	23
34	f. RCIC Pipe Routing Area Temperature - High	~~K~~	10 ~~4~~	1, 2, 3	23
	~~g. Manual Initiation~~	~~NA(e)~~	~~1/system~~	~~1, 2, 3~~	~~24~~
3.3.2	h. RCIC Steam Line Δ Pressure Timer	NA	1	1, 2, 3	23

D10

D09

D10

D06

D09

D10

D15

D06

See Actions for Changes

PTS
Table 3.3.1-1
Function

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.2-1 (Continued)~~
~~ISOLATION ACTUATION INSTRUMENTATION~~

D10

D09

	TRIP FUNCTION	~~ISOLATION SIGNAL[a]~~	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM[b]~~	APPLICABLE OPERATIONAL CONDITION	ACTION
	6. PRIMARY CONTAINMENT ISOLATION				See Actions for Changes
4.a	a. Reactor Vessel Water Level 1) Low, Low - Level 2	~~B~~	3 ~~2~~	1, 2, 3	20
4.b	2) Low, Low, Low - Level 1	~~C~~	3 ~~2~~	1, 2, 3	20
8	b. Drywell Pressure - High	~~H~~	3 ~~2~~	1, 2, 3	20
35	c. North Stack Effluent Radiation - High ~~(c)~~ m	~~W~~	2 ~~1~~	1, 2, 3	23
	~~d.~~ ~~Deleted~~				
36	e. Reactor Enclosure Ventilation Exhaust Duct-Radiation - High	~~S~~	3 ~~2~~	1, 2, 3	23
	~~f.~~ ~~Deleted~~				
	~~g.~~ ~~Deleted~~				
8/3.c	h. Drywell Pressure - High/ Reactor Pressure - Low	~~G~~	3 ~~2/2~~	1, 2, 3	~~26~~
9	i. Primary Containment Instrument Gas Line to Drywell Δ Pressure - Low	~~M~~	1/valve ~~1~~	1, 2, 3	26
	~~j. Manual Initiation~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~24~~

D10

D06

D10

PTS
Table 3.3.1-1
Function

D01

~~TABLE 3.3.2-1 (Continued)~~
~~ISOLATION ACTUATION INSTRUMENTATION~~

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D10

D09

PTS Table 3.3.1-1 Function	TRIP FUNCTION	~~ISOLATION SIGNAL[(a),(c)]~~	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM (b)~~	APPLICABLE OPERATIONAL CONDITION	ACTION
	7. SECONDARY CONTAINMENT ISOLATION				
4.b 8 37 38 36	a. Reactor Vessel Water Level Low, Low - Level 2	~~B~~	3 ~~2~~	1, 2, 3	25
	b. Drywell Pressure - High	~~H~~	3 ~~2~~	1, 2, 3	25
	c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	~~R~~	3 ~~2~~	*#	25
	2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	~~R~~	3 ~~2~~	*#	25
	d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	~~S~~	3 ~~2~~	1, 2, 3	25
	~~e. Deleted~~				
	~~f. Deleted~~				
	~~g. Reactor Enclosure Manual Initiation~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~27~~
	~~h. Refueling Area Manual Initiation~~	~~NA~~	~~1~~	~~*~~	~~25~~

See Actions for Changes

D10

D06

PTS
3.3.1 Action

D01

~~TABLE 3.3.2-1 (Continued)~~
~~ISOLATION ACTUATION INSTRUMENTATION~~
~~ACTION STATEMENTS~~

a.3 and b.3 ~~ACTION 20~~ - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

3, a.3 and b.3 ACTION 21 - Be in at least STARTUP with the associated penetration flow path(s) isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 6 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

14 ~~ACTION 22~~ - Be in at least STARTUP within 6 hours.

4 ~~ACTION 23~~ - In OPERATIONAL CONDITION 1 or 2, verify the affected penetration flow path(s) are isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour and declare the affected system inoperable. In OPERATIONAL CONDITION 3, be in at least COLD SHUTDOWN within 12 hours.

~~ACTION 24 - Restore the manual initiation function to OPERABLE status within 8 hours or isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within the next hour and declare the affected system inoperable or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.~~

D06

6 ~~ACTION 25~~ - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

5 ~~ACTION 26~~ - Isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour.

D06

~~ACTION 27 - Restore the manual initiation function to OPERABLE status within 8 hours or establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.~~

TABLE NOTATIONS

* ~~Required when handling RECENTLY IRRADIATED FUEL in the secondary containment.~~

~~**~~ May be bypassed under administrative control, with all turbine stop valves closed.

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

\# During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

~~(a) DELETED~~

~~(b) 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 provided at least one OPERABLE channel in the same trip system is monitoring that parameter. Trip functions common to RPS Actuation Instrumentation are shown in Table 4.3.2.1-1. In addition, for the HPCI system and RCIC system isolation, provided that the redundant isolation valve, inboard or outboard, as applicable, in each line is OPERABLE and all required actuation instrumentation for that valve is OPERABLE, one channel may be placed in an inoperable status for up to 8 hours for required surveillance without placing the channel or trip system in the tripped condition.~~

D10

Table 3.3.1-1
Function 38 and 39
Applicability

D01

PTS

~~TABLE 3.3.2-1 (Continued)~~

~~TABLE NOTATIONS~~

~~(c)~~ ~~Actuates secondary containment isolation valves. Signal B, H, S, and R also start the standby gas treatment system.~~

D09

~~(d)~~ ~~RWCU system inlet outboard isolation valve closes on SLCS "B" initiation. RWCU system inlet inboard isolation valve closes on SLCS "A" or SLCS "C" initiation.~~

~~(e)~~ ~~Manual initiation isolates the steam supply line outboard isolation valve and only following manual or automatic initiation of the system.~~ D06

(l) ~~(f)~~ In the event of a loss of ventilation the temperature - high setpoint may be raised by 50°F for a period not to exceed 30 minutes to permit restoration of the ventilation flow without a spurious trip. During the 30 minute period, an operator, or other qualified member of the technical staff, shall observe the temperature indications continuously, so that, in the event of rapid increases in temperature, the main steam lines shall be manually isolated.

(m) ~~(g)~~ Wide range accident monitor per Specification 3.3.7.5.

Table 3.3.1-1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.2-2~~

PTS

~~ISOLATION ACTUATION INSTRUMENTATION SETPOINTS~~

D02

~~TRIP~~ FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE
1. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level		
1) Low, Low - Level 2	~~≥ - 38 inches*~~	≥ - 45 inches
2) Low, Low, Low - Level 1	~~≥ - 129 inches*~~	≥ - 136 inches
~~b. DELETED~~	~~DELETED~~	~~DELETED~~
c. Main Steam Line Pressure - Low	~~≥ 840 psig~~	≥ 821 psig
d. Main Steam Line Flow - High	~~≤ 122.1 psid~~	≤ 123 psid
e. Condenser Vacuum - Low	~~10.5 psia~~	≥10.1 psia/≤ 10.9 psia
f. Outboard MSIV Room Temperature - High	~~≤ 192°F~~	≤ 200°F
3.7.9 g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	≤ 165°F	≤ 175°F
~~h. Manual Initiation~~	~~N.A.~~	~~N.A.~~
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		
a. Reactor Vessel Water Level Low - Level 3	~~≥ 12.5 inches*~~	≥ 11.0 inches
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	~~≤ 75 psig~~	≤ 95 psig
~~c. Manual Initiation~~	~~N.A.~~	~~N.A.~~

D06

D02

D06

PTS

Table 3.3.1-1
PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.2-2 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SETPOINTS~~

~~TRIP~~ FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE	
3. REACTOR WATER CLEANUP SYSTEM ISOLATION			
a. RWCS Δ Flow - High	~~≤ 54.9 gpm~~	≤ 65.2 gpm	D02
b. RWCS Area Temperature - High	~~≤ 155°F or ≤ 120°F**~~	≤ 160°F or ≤ 125°F**	
c. RWCS Area Ventilation Δ Temperature - High	~~≤ 52°F or ≤ 32°F**~~	≤ 60°F or ≤ 40°F**	
d. SLCS Initiation	~~N.A.~~	N.A.	
e. Reactor Vessel Water Level - Low, Low, - Level 2	~~≥ -38 inches *~~	≥ -45 inches	
~~f. Manual Initiation~~	~~N.A.~~	~~N.A.~~	D06
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION			
a. HPCI Steam Line Δ Pressure - High	~~≤ 974"~~ H_2O	≤ 984" H_2O	
b. HPCI Steam Supply Pressure - Low	≥ ~~100~~ psig	≥ 90 psig	
c. HPCI Turbine Exhaust Diaphragm Pressure - High	~~≤ 10~~ psig	≤ 20 psig	D02
d. HPCI Equipment Room Temperature - High	~~180°F~~	≥ 177°F, ≤ 191°F	
e. HPCI Equipment Room Δ Temperature - High	~~≤ 104°F~~	≤ 108.5°F	
f. HPCI Pipe Routing Area Temperature - High	~~180°F~~	≥ 177°F, ≤ 191°F	
~~g. Manual Initiation~~	~~N.A.~~	~~N.A.~~	D06
3.3.2 h. HPCI Steam Line Δ Pressure - Timer	3 ≤ τ ≤ 12.5 seconds	2.5 ≤ τ ≤ 13 seconds	

D01

Table 3.3.1-1
PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

PTS

~~TABLE 3.3.2-2 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SETPOINTS~~

D02

~~TRIP~~ FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a. RCIC Steam Line Δ Pressure - High	~~≤ 373" H_2O~~	≤ 381" H_2O
b. RCIC Steam Supply Pressure - Low	~~≥ 64.5 psig~~	≥ 56.5 psig
c. RCIC Turbine Exhaust Diaphragm Pressure - High	~~≤ 10.0 psig~~	≤ 20.0 psig
d. RCIC Equipment Room Temperature - High	~~180°F~~	≥ 161°F, ≤ 191°F
e. RCIC Equipment Room Δ Temperature - High	~~≤ 109°F~~	≤ 113.5°F
f. RCIC Pipe Routing Area Temperature - High	~~180°F~~	≥ 161°F, ≤ 191°F
~~g. Manual Initiation~~	~~N.A.~~	~~N.A.~~
3.3.2 h. RCIC Steam Line Δ Pressure Timer	3 ≤ τ ≤ 12.5 seconds	2.5 ≤ τ ≤ 13 seconds

D06

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.2-2 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SETPOINTS~~

~~TRIP FUNCTION~~	~~TRIP SETPOINT~~	ALLOWABLE VALUE
6. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level		
1. Low, Low - Level 2	~~≥ -38 inches*~~	≥ -45 inches
2. Low, Low, Low, Level 1	~~≥ -129 inches*~~	≥ -136 inches
b. Drywell Pressure - High	~~≤ 1.68 psig~~	≤ 1.88 psig
c. North Stack Effluent Radiation - High	~~≤ 2.1 μCi/cc~~	≤ 4.0 μCi/cc
~~d.~~ ~~Deleted~~		
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	~~≤ 1.35 mR/h~~	≤ 1.5 mR/h
~~f.~~ ~~Deleted~~		
~~g.~~ ~~Deleted~~		
h. Drywell Pressure - High/ Reactor Pressure - Low	~~≤ 1.68 psig/~~ ~~≥ 455 psig (decreasing)~~	≤ 1.88 psig/ ≥ 435 psig (decreasing)
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	~~≥ 2.0 psi~~	≥ 1.9 psi
~~j. Manual Initiation~~	~~N.A.~~	~~N.A.~~

D02

D06

Table 3.3.1-1
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

PTS

~~TABLE 3.3.2-2 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SETPOINTS~~

~~TRIP FUNCTION~~	~~TRIP SETPOINT~~	ALLOWABLE VALUE
7. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low, Low - Level 2	~~≥ -38 inches*~~	≥ -45 inches
b. Drywell Pressure - High	~~≤ 1.68 psig~~	≤ 1.88 psig
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	~~≤ 2.0 mR/h~~	≤ 2.2 mR/h
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	~~≤ 2.0 mR/h~~	≤ 2.2 mR/h
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	~~≤ 1.35 mR/h~~	≤ 1.5 mR/h
~~e.~~ ~~Deleted~~		
~~f.~~ ~~Deleted~~		
~~g. Reactor Enclosure Manual Initiation~~	~~N.A.~~	~~N.A.~~
~~h. Refueling Area Manual Initiation~~	~~N.A.~~	~~N.A.~~

D02

D06

D06

~~* See Bases Figure B 3/4 3-1.~~

D09

** The low setpoints are for the RWCU Heat Exchanger Rooms; the high setpoints are for the pump rooms.

Footnote (j)

FEB 1 4 1996

PTS

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
1. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level	
1) Low, Low - Level 2	N.A.
2) Low, Low, Low - Level 1	≤1.0###*
b. DELETED	DELETED
c. Main Steam Line Pressure - Low	≤1.0###*
d. Main Steam Line Flow - High	≤1.0###*
e. Condenser Vacuum - Low	N.A.
3.3.2 f. Outboard MSIV Room Temperature - High	N.A.
3.7.9 g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High	N.A.
h. Manual Initiation	N.A.
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
a. Reactor Vessel Water Level Low - Level 3	N.A.
3.3.2 b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	N.A.
c. Manual Initiation	N.A.
3. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. RWCS Δ Flow - High	N.A.##
b. RWCS Area Temperature - High	N.A.
c. RWCS Area Ventilation Δ Temperature - High	N.A.
d. SLCS Initiation	N.A.
e. Reactor Vessel Water Level - Low, Low - Level 2	N.A.
f. Manual Initiation	N.A.

PTS

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION	
a. HPCI Steam Line Δ Pressure - High	N.A.
b. HPCI Steam Supply Pressure - Low	N.A.
c. HPCI Turbine Exhaust Diaphragm Pressure - High	N.A.
d. HPCI Equipment Room Temperature - High	N.A.
e. HPCI Equipment Room Δ Temperature - High	N.A.
3.3.2 f. HPCI Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. RCIC Steam Line Δ Pressure - High	N.A.
b. RCIC Steam Supply Pressure - Low	N.A.
c. RCIC Turbine Exhaust Diaphragm Pressure - High	N.A.
d. RCIC Equipment Room Temperature - High	N.A.
e. RCIC Equipment Room Δ Temperature - High	N.A.
f. RCIC Pipe Routing Area Temperature - High	N.A.
g. Manual Initiation	N.A.

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
6. PRIMARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level	
1) Low, Low - Level 2	N.A.
2) Low, Low, Low - Level 1	N.A.
b. Drywell Pressure - High	N.A.
c. North Stack Effluent Radiation - High	N.A.
d. Deleted	
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High	N.A.
f. Deleted	
g. Deleted	
3.3.2 h. Drywell Pressure - High/ Reactor Pressure - Low	N.A.
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	N.A.
j. Manual Initiation	N.A.
7. SECONDARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level Low, Low - Level 2	N.A.
b. Drywell Pressure - High	N.A.
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	N.A.
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	N.A.
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High	N.A.
e. Deleted	

TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
f. Deleted	
g. Reactor Enclosure Manual Initiation	N.A.
h. Refueling Area Manual Initiation	N.A.

TABLE NOTATIONS

(a) DELETED

3.3.2 (b) DELETED

* Isolation system instrumentation response time for MSIV only. No diesel generator delays assumed for MSIVs.

** DELETED

\# Isolation system instrumentation response time specified for the Trip Function actuating each valve group shall be added to the isolation time for the valves in each valve group to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.

\## With 45 second time delay.

\### Sensor is eliminated from response time testing for the MSIV actuation logic circuits. Response time testing and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required.

Amendment No. ~~52~~, ~~74~~, ~~93, 10~~
OCT 1 2000

D01

~~TABLE 4.3.2.1-1~~

See Table 3.3.2-1 for Changes

~~ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

~~TRIP FUNCTION~~	~~CHANNEL CHECK (a)~~	~~CHANNEL FUNCTIONAL TEST (a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low, Level 2				1, 2, 3
2) Low, Low, Low - Level 1				1, 2, 3
b. DELETED				DELETED
c. Main Steam Line Pressure - Low				1
4.3.1.1 d. Main Steam Line Flow - High				1, 2, 3
e. Condenser Vacuum - Low				1, 2**, 3**
f. Outboard MSIV Room Temperature - High				1, 2, 3
3.7.9 g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High				1, 2, 3
~~h. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
4.3.1.1 a. Reactor Vessel Water Level~~##~~ Low - Level 3				1, 2, 3
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High				1, 2, 3
~~c. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~

D04

D06

D10

D04

D06

D01

~~TABLE 4.3.2.1-1 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

~~TRIP~~ FUNCTION	~~CHANNEL CHECK (a)~~	~~CHANNEL FUNCTIONAL TEST (a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
3. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCS Δ Flow - High				1, 2, 3
b. RWCS Area Temperature - High				1, 2, 3
4.3.1.1 c. RWCS Area Ventilation Δ Temperature - High				1, 2, 3
d. SLCS Initiation	N.A.		N.A.	1, 2, 3
e. Reactor Vessel Water Level Low, Low, - Level 2				1, 2, 3
~~f. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High				1, 2, 3
b. HPCI Steam Supply Pressure, Low				1, 2, 3
4.3.1.1 c. HPCI Turbine Exhaust Diaphragm Pressure - High				1, 2, 3
d. HPCI Equipment Room Temperature - High				1, 2, 3
e. HPCI Equipment Room Δ Temperature - High				1, 2, 3
f. HPCI Pipe Routing Area Temperature - High				1, 2, 3
~~g. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~
3.3.2 h. HPCI Steam Line Δ Pressure Timer	N.A.			1, 2, 3

D04

D06

D04

D06

~~TS 3.3.1~~ D01

See Table 3.3.2-1 for Changes

~~TABLE 4.3.2.1-1 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

PTS

~~TRIP~~ FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High				1, 2, 3
b. RCIC Steam Supply Pressure - Low				1, 2, 3
4.3.1.1 c. RCIC Turbine Exhaust Diaphragm Pressure - High				1, 2, 3
d. RCIC Equipment Room Temperature - High				1, 2, 3
e. RCIC Equipment Room Δ Temperature - High				1, 2, 3
f. RCIC Pipe Routing Area Temperature - High				1, 2, 3
~~g. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~
3.3.2 h. RCIC Steam Line Δ Pressure Timer	N.A.			1, 2, 3

D04

D06

~~TABLE 4.3.2.1-1 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

PTS

See Table 3.3.2-1 for Changes

~~TRIP FUNCTION~~	~~CHANNEL CHECK (a)~~	~~CHANNEL FUNCTIONAL TEST (a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
6. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low - Level 2				1, 2, 3
4.3.1.1 2) Low, Low, Low - Level 1				1, 2, 3
b. Drywell Pressure ## - High				1, 2, 3
c. North Stack Effluent Radiation - High				1, 2, 3
d. ~~Deleted~~				
e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High				1, 2, 3
f. ~~Deleted~~				
g. ~~Deleted~~				
h. Drywell Pressure - High/ Reactor Pressure - Low				1, 2, 3
i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low	~~N.A.~~			1, 2, 3
~~j. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~

D10

D04

D06

D01

PTS

~~TABLE 4.3.2.1-1 (Continued)~~

~~ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

See Table 3.3.2-1 for Changes

~~TRIP~~ FUNCTION	~~CHANNEL CHECK(a)~~	~~CHANNEL FUNCTIONAL TEST(a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
7. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level Low, Low - Level 2				1, 2, 3
b. Drywell Pressure## - High				1, 2, 3
c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High				*#
2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High				*#
d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High				1, 2, 3
~~e. Deleted~~				
~~f. Deleted~~				
~~g. Reactor Enclosure Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~
~~h. Refueling Area Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~*~~

4.3.3.1

D09

D04

D06

D04

~~(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.~~

*Required when handling RECENTLY IRRADIATED FUEL in the secondary containment.

**When not administratively bypassed and/or when any turbine stop valve is open.

#During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

See Table 3.3.2-1 Changes

~~##These trip functions (2a, 6b, and 7b) are common to the RPS actuation trip function.~~

D09

PTS

INSTRUMENTATION D01

~~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~~ D02
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~~1-1

ACTION: D01

~~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.~~ D02

Actions a.2 and b.2 b. With one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.~~3~~1-1. D01

~~c. With either ADS trip system subsystem inoperable, restore the inoperable trip system to OPERABLE status within:~~ D18

~~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.~~

Actions a.3 and b.3 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.~~ D04

~~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.~~

3.3.2 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 3.3.1-1
PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.3-1~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~

D10

See Actions for Changes

PTS Table 3.3.1-1 Function	~~TRIP~~ FUNCTION	MINIMUM OPERABLE CHANNELS ~~PER TRIP FUNCTION~~(a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION	
	1. CORE SPRAY SYSTEM~~***~~				
4.a	a. Reactor Vessel Water Level - Low Low Low, Level 1	3 ~~2/pump(b)~~	1, 2, 3	30	
8	b. Drywell Pressure - High	3 ~~2/pump(b)~~	1, 2, 3,	30	D10
3.c	c. Reactor Vessel Pressure - Low (Permissive)	3 ~~6(b)~~	1, 2, 3	31	
	~~d. Manual Initiation~~	~~2(e)~~	~~1, 2, 3~~	~~33~~	D06
	2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM~~***~~				D10
4.a	a. Reactor Vessel Water Level - Low Low Low, Level 1	3 ~~2~~	1, 2, 3	30	
8	b. Drywell Pressure - High	3 ~~2~~	1, 2, 3	30	D18
3.c	c. Reactor Vessel Pressure - Low (Permissive)	~~2~~ 3	1, 2, 3	31	
12	d. Injection Valve Differential Pressure-Low (Permissive)	1/valve	1, 2, 3	31	
	~~e. Manual Initiation~~	~~1~~	~~1, 2, 3~~	~~33~~	D06
Note (o)	3. HIGH PRESSURE COOLANT INJECTION SYSTEM~~##~~ (o)				D10
4.b	a. Reactor Vessel Water Level - Low Low, Level 2	3 ~~4~~	1, 2, 3	34	
8 Note (p)	b. Drywell Pressure - High~~###~~ (p)	3 ~~4~~	1, 2, 3	34	
10	c. Condensate Storage Tank Level - Low	~~2(c)~~ 3	1, 2, 3	35	
13	d. Suppression Pool Water Level - High	2(d)	1, 2, 3	35	
4.c	e. Reactor Vessel Water Level - High, Level 8	3 ~~4~~	1, 2, 3	31	
	~~f. Manual Initiation~~~~###~~	~~1/system~~	~~1, 2, 3~~	~~33~~	D06

PTS
Table 3.3.1-1
Function

TABLE 3.3.1-1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TS 3.3.1

D01

~~TABLE 3.3.3-1 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~

See Actions for Changes

LIMERICK - UNIT 2

~~TRIP~~ FUNCTION	MINIMUM OPERABLE CHANNELS ~~PER TRIP FUNCTION~~ (a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
Note (n) 4. AUTOMATIC DEPRESSURIZATION SYSTEM~~#***~~	D10		
4.a 8 a. Reactor Vessel Water Level - Low Low Low, Level 1	3 ~~2~~	1, 2, 3	30 D10
3.3.2 b. Drywell Pressure - High	3 ~~2~~	1, 2, 3	30
11 c. ADS Timer	1	1, 2, 3	31 D17
11 d. Core Spray Pump Discharge Pressure - High (Permissive)	~~2~~ 6	1, 2, 3	~~31~~ D18
e. RHR LPCI Mode Pump Discharge Pressure High (Permissive)	~~4~~	1, 2, 3	31
5.a f. Reactor Vessel Water Level - Low, Level 3 (Permissive)	~~1~~ 3	1, 2, 3	31 D10
~~g. Manual Initiation~~	~~2~~	~~1, 2, 3~~	~~33~~ D06
3.3.2 h. ADS Drywell Pressure Bypass Timer	2	1, 2, 3	31

3/4 3-34

	TOTAL NO. OF CHANNELS(f)	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
5. LOSS OF POWER					
3.3.5 1. 4.16 kV Emergency Bus Under-voltage (Loss of Voltage)	1/bus	1/bus	1/bus	1, 2, 3, 4**, 5**	36
2. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	1/source/ bus	1/source/ bus	1/source/ bus	1, 2, 3, 4**, 5**	37

D10

~~***The Minimum OPERABLE Channels Per Trip Function is per subsystem.~~

PTS
Table 3.3.1-1
Notes

D01

~~TABLE 3.3.3-1 (Continued)~~
~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~
~~TABLE NOTATIONS~~

~~(a) 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 provided at least one OPERABLE channel in the same trip system is monitoring that parameter.~~ D04

~~(b) Also provides input to actuation logic for the associated emergency diesel generators~~. D09

~~(c) One trip system. Provides signal to HPCI pump suction valves only.~~ D10

~~(d) On 1 out of 2 taken twice logic, provides a signal to trip the HPCI pump turbine only.~~

~~(e) The manual initiation push buttons start the respective core spray pump and diesel generator. The "A" and "B" logic manual push buttons also actuate an initiation permissive in the injection valve opening logic.~~ D09

3.3.5 (f) A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2.

~~* DELETED~~

Note (n) ~~#~~ Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

3.3.5 ** Required when ESF equipment is required to be OPERABLE.

Note (o) ~~##~~ Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

Note (p) ~~###~~ The injection function~~s~~ of Drywell Pressure - High ~~and Manual Initiation are~~ is not required to be OPERABLE with reactor steam dome pressure less than 550 psig. D06

PTS
3.3.1
Action

D01

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

D03

~~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 in accordance with the Risk Informed Completion Time Program, or declare the associated system inoperable.~~

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

7 ~~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. D10

~~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 in accordance with the Risk Informed Completion Time Program*, or declare the associated ECCS inoperable.~~ D06

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

D03

~~a.~~ ~~For one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or in accordance with the Risk Informed Completion Time Program, 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 in accordance with the Risk Informed Completion Time Program*, or~~ declare the HPCI system inoperable.

8

D03

3.3.5 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.

~~*Not applicable when trip capability is not maintained.~~

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

3.3.5

ACTION 37 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable device in the bypassed condition subject to the following conditions:

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable. 127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

D01

~~TABLE 3.3.3-2~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS~~

		~~TRIP~~ FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE	
	1.	CORE SPRAY SYSTEM			D02
	a.	Reactor Vessel Water Level - Low Low Low, Level 1	~~$\geq$ -129 inches*~~	$\geq$ -136 inches	
	b.	Drywell Pressure - High	~~$\leq$ 1.68 psig~~	$\leq$ 1.88 psig	
	c.	Reactor Vessel Pressure - Low	~~$\geq$ 455 psig,(decreasing)~~	$\geq$ 435 psig, (decreasing)	D06
	~~d.~~	~~Manual Initiation~~	~~N.A.~~	~~N.A.~~	
	2.	LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM			D02
	a.	Reactor Vessel Water Level - Low Low Low, Level 1	~~$\geq$ -129 inches*~~	$\geq$ -136 inches	
	b.	Drywell Pressure - High	~~$\leq$ 1.68 psig~~	$\leq$ 1.88 psig	
	c.	Reactor Vessel Pressure - Low	~~$\geq$ 455 psig,(decreasing)~~	$\geq$ 435 psig, (decreasing)	
	d.	Injection Valve Differential Pressure - Low	~~$\geq$ 74 psid, (decreasing)~~	$\geq$ 64 psid and $\leq$ 84 psid	D06
	~~e.~~	~~Manual Initiation~~	~~N.A.~~	~~N.A.~~	
	3.	HIGH PRESSURE COOLANT INJECTION SYSTEM			
	a.	Reactor Vessel Water Level - Low Low, Level 2	$\geq$ -38 inches*	$\geq$ -45 inches	D02
	b.	Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig	
	c.	Condensate Storage Tank Level - Low	$\geq$ 167.8 inches**	$\geq$ 164.3 inches	
	d.	Suppression Pool Water Level - High	$\leq$ 24 feet 1.5 inches	$\leq$ 24 feet 3 inches	
	e.	Reactor Vessel Water Level - High, Level 8	$\leq$ 54 inches	$\leq$ 60 inches	D06
	~~f.~~	~~Manual Initiation~~	~~N.A.~~	~~N.A.~~	
	4.	AUTOMATIC DEPRESSURIZATION SYSTEM			D02
	a.	Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -129 inches*	$\geq$ -136 inches	
	b.	Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig	
3.3.2	c.	ADS Timer	$\leq$ 105 seconds	$\leq$ 117 seconds	
	d.	Core Spray Pump Discharge Pressure - High	$\geq$ 145 psig,(increasing)	$\geq$ 125 psig, (increasing),	D02
	e.	RHR LPCI Mode Pump Discharge Pressure-High	$\geq$ 125 psig,(increasing)	$\geq$ 115 psig, (increasing)	
	f.	Reactor Vessel Water Level-Low, Level 3	$\geq$ 12.5 inches	$\geq$ 11.0 inches	D06
	~~g.~~	~~Manual Initiation~~	~~N.A.~~	~~N.A.~~	
3.3.2	h.	ADS Drywell Pressure Bypass Timer	$\leq$ 420 seconds	$\leq$ 450 seconds	

~~*See Bases Figure B 3/4.3-1.~~

~~**Corresponds to 2.3 feet indicated.~~

D09

~~TABLE 3.3.3-2 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS~~

TRIP FUNCTION		TRIP SETPOINT	ALLOWABLE VALUE
5. LOSS OF POWER	RELAY		
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X	NA	NA
b. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	RELAY		
3.3.5	127-11X0X and 102-11X0X	a. 4.16 kV Basis 2905 ± 115 volts	2905 ± 145 volts
		b. 120 V Basis 83 ± 3 volts	83 ± 4 volts
		c. ≤ 1 second time delay	≤ 1.5 second time delay
	127Y-11X0X** and 127Y-1-11X0X	a. 4.16 kV Basis 3640 ± 91 volts	3640 ± 182 volts
		b. 120 V Basis 104 ± 3 volts	104 ± 5.2 volts
		c. ≤ 52 second time delay	≤ 60 second time delay
	127Z-11X0X and 162Y-11X0X	a. 4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b. 120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c. ≤ 10 second time delay	≤ 11 second time delay
	127Z-11X0X and 162Z-11X0X	a. 4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b. 120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c. ≤ 61 second time delay	≤ 64 second time delay

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

PTS

TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES

	ECCS	RESPONSE TIME (Seconds)
3.3.2	1. CORE SPRAY SYSTEM	≤ 27#
	2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM	≤ 40#
	3. AUTOMATIC DEPRESSURIZATION SYSTEM	N.A.
	4. HIGH PRESSURE COOLANT INJECTION SYSTEM	≤ 60#
3.3.5	5. LOSS OF POWER	N.A.

3.3.2 # ECCS actuation instrumentation is eliminated from response time testing.

D01

PTS

~~TABLE 4.3.3.1-1~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

See CTS Table 3.3.1-1 for Changes

PTS	~~TRIP~~ FUNCTION	~~CHANNEL CHECK(a)~~	~~CHANNEL FUNCTIONAL TEST (a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED	
	1. CORE SPRAY SYSTEM					D04
	a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3	
4.3.1.1	b. Drywell Pressure - High				1, 2, 3	
	c. Reactor Vessel Pressure - Low				1, 2, 3	
	~~d. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~	D06
	2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM					
	a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3	
4.3.1.1	b. Drywell Pressure - High				1, 2, 3	D04
	c. Reactor Vessel Pressure - Low				1, 2, 3	
	d. Injection Valve Differential Pressure - Low (Permissive)				1, 2, 3	
	~~e. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~	D06
	3. HIGH PRESSURE COOLANT INJECTION SYSTEM***					
Table 3.3.1-1 Note (o)	a. Reactor Vessel Water Level - Low Low, Level 2				1, 2, 3	
	b. Drywell Pressure - High				1, 2, 3	
	c. Condensate Storage Tank Level - Low				~~1, 2, 3~~	D04
4.3.1.1	d. Suppression Pool Water Level - High				1, 2, 3	
	e. Reactor Vessel Water Level - High, Level 8				1, 2, 3	
	~~f. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~	D06

D01

See CTS Table 3.3.1-1 for Changes

~~TABLE 4.3.3.1-1 (Continued)~~

PTS

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

	~~TRIP~~ FUNCTION	~~CHANNEL CHECK (a)~~	~~CHANNEL FUNCTIONAL TEST (a)~~	~~CHANNEL CALIBRATION(a)~~	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
Table 3.3.1-1 Note (n)	4. AUTOMATIC DEPRESSURIZATION SYSTEM#				
4.3.1.1	a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3
	b. Drywell Pressure - High				1, 2, 3
3.3.2	c. ADS Timer	N.A.			1, 2, 3
	d. Core Spray Pump Discharge Pressure - High				1, 2, 3
	e. RHR LPCI Mode Pump Discharge Pressure - High				1, 2, 3
	f. Reactor Vessel Water Level - Low, Level 3				1, 2, 3
D06	~~g. Manual Initiation~~	~~N.A.~~		~~N.A.~~	~~1, 2, 3~~
3.3.2	h. ADS Drywell Pressure Bypass Timer	N.A.			1, 2, 3
3.3.5	5. LOSS OF POWER				
	a. 4.16 kV Emergency Bus Under voltage (Loss of Voltage)##	N.A.		N.A.	1, 2, 3, 4**, 5**
	b. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)				1, 2, 3, 4**, 5**

D04

D04

~~(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.~~

~~* DELETED~~

3.3.5 Note (o) ** Required OPERABLE when ESF equipment is required to be OPERABLE.

*** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

Loss of Voltage Relay 127-11X is not field setable.

3.3.5 Note (n)`

INSTRUMENTATION

~~END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION~~ D01

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~~ SYSTEM RESPONSE TIME as shown with the END-OF-CYCLE RECIRCULATION PUMP TRIP in Table 3.3.4.2-3. D02

3.3.4.2

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

Table 3.3.1-1 Note (h)

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.~~ D02

3.3.1 Action a.1.

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 ~~or in accordance with the Risk Informed Completion Time Program*.~~ D03

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~~: D03

Action 11

~~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 or in accordance with the Risk Informed Completion Time Program.~~

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

3.3.4.2

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 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.

~~*Not applicable when trip capability is not maintained.~~ D03

INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

4.3.1.1 ~~4.3.4.2.1 Each of the required end-of-cycle recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST, including trip system logic testing, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program~~.

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

3.3.4.2

4.3.4.2.3 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each trip function shown in Table 3.3.4.2-3 shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit.

4.3.4.2.4 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured in accordance with the Surveillance Frequency Control Program.

~~TABLE 3.3.4.2-1~~

~~END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION~~

D01

PTS

D10

TABLE 3.3.1-1`
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

~~TRIP~~ FUNCTION	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM*~~
20 1. Turbine Stop Valve - Closure	3 ~~2**~~
21 2. Turbine Control Valve-Fast Closure	3 ~~2**~~

~~* A trip system may be placed in an inoperable status for up to 6 hours for required surveillance provided that the other trip system is OPERABLE.~~

** This function shall be automatically bypassed when turbine first stage pressure is equivalent to THERMAL POWER LESS than 29.5% of RATED THERMAL POWER.

Table 3.3.1-1 Applicability Functions 21 & 22

TABLE 3.3.4.2-2

END-OF-CYCLE RECIRCULATION PUMP TRIP SETPOINTS

D01

~~TRIP~~ FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE
1. Turbine Stop Valve-Closure	~~≤ 5% closed~~	≤ 7% closed
2. Turbine Control Valve-Fast Closure	~~≥ 500 psig~~	≥ 465 psig

D02

PTS

3.3.4.2

TABLE 3.3.4.2-3

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Milliseconds)
1. Turbine Stop Valve-Closure	$\leq$ 175
2. Turbine Control Valve-Fast Closure	$\leq$ 175

~~INFORMATION ON THIS PAGE HAS BEEN DELETED~~

PTS

INSTRUMENTATION

~~3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION~~ D01

LIMITING CONDITION FOR OPERATION

3.3.1 ~~3.3.5 The reactor core isolation cooling (RCIC) system actuation instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.5-2.~~ D02

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

ACTION:

~~a. With a RCIC system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.5-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.~~ D02

3.3.1 Action a.1 and b.1 b. With one or more RCIC system actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.5-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1 ~~4.3.5.1 Each of the required RCIC 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. CHANNEL CHECK and CHANNEL CALIBRATION are not required for manual initiation.~~ D04

~~4.3.5.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.~~

TABLE 3.3.1-1`
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

PTS

~~TABLE 3.3.5-1~~

~~REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION~~

Table 3.3.1-1 Function

See Actions for Changes

	~~FUNCTIONAL UNITS~~	MINIMUM OPERABLE CHANNELS ~~PER TRIP FUNCTION*~~	ACTION	
4.b	a. Reactor Vessel Water Level - Low Low, Level 2	3 ~~4#~~	50	D10
4.c	b. Reactor Vessel Water Level - High, Level 8	3 ~~4#~~	~~51~~	D17
10	c. Condensate Storage Tank Water Level - Low	3 ~~2**~~	52	
	~~d. Manual Initiation##~~	~~1/system***~~	~~53~~	D06

~~*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 provided all other channels monitoring that parameter are OPERABLE.~~ D04

~~**One trip system with one-out-of-two logic.~~ D10

~~***One trip system with one channel.~~ D06

~~#One trip system with one-out-of-two twice logic.~~ D10

~~##The injection function of Manual Initiation is not required to be OPERABLE with reactor steam dome pressure less than 550 psig.~~ D06

~~TABLE 3.3.5-1 (Continued)~~ D01

~~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:~~ D03

~~a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or in accordance with the Risk Informed Completion Time Program, 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.~~ D17

~~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 in accordance with the Risk Informed Completion Time Program*, or declare the RCIC system inoperable.~~ D03

~~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.~~ D06

~~* Not applicable when trip capability is not maintained.~~

TABLE 3.3.1-1`
PLANT PROTECTION SYSTEM
INSTRUMENTATION CHANNELS

D01

~~TABLE 3.3.5-2~~

~~REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS~~

FUNCTIONAL UNITS	~~TRIP SETPOINT~~	ALLOWABLE VALUE
a. Reactor Vessel Water Level - Low Low, Level 2	~~≥ -38 inches*~~	≥ -45 inches
b. Reactor Vessel Water Level - High, Level 8	~~≤ 54 inches~~	≤ 60 inches
c. Condensate Storage Tank Level - Low	~~≥ 135.8** inches~~	≥ 132.3 inches
~~d. Manual Initiation~~	~~N.A.~~	~~N.A.~~

D02

D06

~~*See Bases Figure B 3/4.3-1.~~

~~**Corresponds to 2.3 feet indicated.~~

D09

Discussion of Changes

Discussion of Changes

Technical Specification 3/4.3.1,
Plant Protection System Instrumentation Channels

As an editorial improvement, items marked "Deleted" in the current TS and pages marked as "Intentionally Blank" are not included in the proposed TS.

D01

The instrumentation channel functions in current TSs 2.2.1, "Limiting Safety System Settings," 3.3.1, "Reactor Protection System Instrumentation," 3.3.2, "Isolation Actuation Instrumentation," 3.3.3, "Emergency Core Cooling System Actuation Instrumentation," 3.3.4.2, "End of Cycle Recirculation Pump Trip System Instrumentation," and 3.3.5, "Reactor Core Isolation Cooling System Actuation Instrumentation," are combined into the proposed TS 3.3.1, "Plant Protection System Instrumentation Channels."

The proposed changes are acceptable because the reorganization and relabeling of the existing requirements does not result in any technical changes to the requirements. Any technical changes related to the reorganization are discussed in other sections below.

LSSS 2.2.1 and LCOs in current TSs 3.3.1, 3.3.2, 3.3.3, 3.3.4.2, and 3.3.5 require the trip setpoints to be set consistent with the values shown in the Trip Setpoint Column in the associated table of Allowable Values and Trip Setpoints.

D02

LSSS 2.2.1 and current TSs 3.3.2, 3.3.3, 3.3.4.2, and 3.3.5 contain an Action which states that with the channel trip setpoint less conservative than the Allowable Value to declare the channel inoperable and adjust the trip setpoint consistent with the Trip Setpoint value. LSSS 2.2.1 and current TSs 3.3.2, 3.3.3, 3.3.4.2, and 3.3.5 each contain a table of Allowable Values and Trip Setpoints for the associated functions. In the proposed TSs, the trip setpoint column of each of these tables is relocated to licensee control. The LSSS, LCO, Action and other references to trip setpoints and actions to adjust the channel trip setpoint consistent with the trip setpoint are deleted.

The purpose of the trip setpoint requirements is to ensure required automatic safety systems are actuated to protect against violating core design limits, breaching the reactor coolant system (RCS) pressure boundary, and to mitigate accidents. In accordance with 10 CFR 50.36(c)(1)(ii)(A), if it is determined that an automatic protective device for a variable on which a safety limit has been placed (i.e., a limiting safety system setting) does not function as required, appropriate action is taken to ensure the abnormal situation is corrected before a safety limit is exceeded, which may include shutting down the reactor. The CEG instrument setpoint methodology follows General Electric (GE) Topical Report NEDC-31336P, "General Electric Instrument Setpoint Methodology," which has been found to be acceptable by the NRC for selecting instrumentation setpoints (ADAMS Accession No. ML20044B611). Additionally, pre-defined limits (i.e., "as-found" limits and "as-left" limits) are determined for each instrument consistent with the guidance provided in Regulatory Guide (RG) 1.105, "Setpoints for Safety-Related Instrumentation," and American National Standards Institute (ANSI)/International Society of Automation (ISA) Standard ANSI/ISA-RP67.04, " Setpoints for Safety-Related Instrumentation."

The removal of these details from the TSs is acceptable because this type of information is not necessary to provide adequate protection of public health and safety. The proposed TS retain the Allowable Values associated with the instrumentation channels, which are designated as the operability limits for the required Functions. In addition, this change is acceptable because these types of procedural details will be adequately controlled under the requirements of 10 CFR 50.59, which ensures changes are properly evaluated. The removal of other references to trip setpoints are made to be consistent with the relocation of the trip setpoints.

D03

The Actions, table Actions, and associated notes in current TSs 3.3.1, 3.3.2, 3.3.3, 3.3.4.2, and 3.3.5 are replaced with the proposed TS 3.3.1, "Plant Protection System Instrumentation Channels" Actions, the Actions in proposed Table 3.3.1-1, and associated Notes. These proposed changes are identified on the associated proposed TS markup pages as "D03."

There are three principal differences between the existing TS Actions and the Actions in proposed TS 3.3.1 and Table 3.3.3-1:

- The current instrumentation coincidence logic is one-out-of-two-taken-twice and many existing Actions are based on ensuring an actuation will occur considering the alignment of inoperable channels and trip systems. Under the new design, the coincidence logic is based on two-out-of-four channels and the concept of channels per trip system no longer applies. As a result, many existing Actions are no longer appropriate under the new design.
- The current TS requirements repeat many instrument functions for various actuated systems (reactor trip, isolation, ECCS initiation, etc.) The actions for a particular inoperable channel may vary based on the actuated system. For the same channel, the current TS actions may be incompatible (e.g., one current TS may permit continued operation while another TS may require a plant shutdown). Under the new design, instrument channels are not repeated based on the actuated system. Some Actions are included in the proposed TS while others are eliminated to preserve consistent actions for the same inoperable channel. Eliminated actions are described and justified below.
- Several current TS Actions permit the use of a Risk Informed Completion Time (RICT) as an alternative to the fixed Completion Time. Because of the reorganization of the requirements in the proposed TS and changes to the design, some existing RICTs are removed at this time. If the reorganization and design changes do not affect the application of the RICT Program, the RICTs have been retained.

Eliminated Actions:

Current TS 3.3.1, Action a, b, c, and d and the associated Notes *, **, and *** are designed to ensure that sufficient channels are operable to actuate a reactor trip under the one-out-of-two-taken-twice coincidence logic of the current design. Action d also provides the option to initiate the action identified in Table 3.3.1-1 in lieu of Acton a, b, or c. Under the new design, the coincidence logic is based on two-out-of-four channels and the concept of channels per trip system no longer applies. As a result, the existing Actions are no longer appropriate and are replaced.

Current TS 3.3.2, Action a, b, and c and the associated Notes *, **, and # are designed to ensure that sufficient channels are operable to provide an isolation signal under the one-out-of-two-taken-twice coincidence logic of the current design. Action b.1 also provides the option to initiate the action identified in Table 3.3.2-1 in lieu of placing the inoperable channel in trip. Under the new design, the coincidence logic is based on two-out-of-four channels and the concept of channels per trip system no longer applies. As a result, the existing Actions are no longer appropriate and are replaced.

Current TS 3.3.3, Table 3.3.3-1, Action 30, requires placing an inoperable channel in the tripped condition within 24 hours or declaring the associated system inoperable. This action is incompatible with more restrictive actions applicable to the associated functions: "Reactor Vessel Water Level - Low Low Low, Level 1," and "Drywell Pressure - High." Therefore, Action 30 is removed.

Current TS 3.3.3, Table 3.3.3-1, Action 34, requires placing an inoperable channel in the tripped condition within 24 hours or declaring the High Pressure Coolant Injection (HPCI) system inoperable. This action is incompatible with more restrictive actions applicable to the associated functions: "Reactor Vessel Water Level - Low Low, Level 2," and "Drywell Pressure - High." Therefore, Action 34 is removed.

Current TS 3.3.3, Table 3.3.3-1, Action 35, requires placing an inoperable channel in the tripped condition within 24 hours or declaring the HPCI system inoperable. This action is incompatible with more restrictive actions applicable to the associated functions: "Condensate Storage Tank Level - Low," and "Suppression Pool Water Level - High." Therefore, Action 34 is revised to declare the HPCI system inoperable as proposed Action 8.

Current TS 3.3.4.2, Actions b and c, and Note * are designed to ensure that sufficient channels are operable to provide an EOC-RPT actuation signal under the one-out-of-two-taken-twice coincidence logic of the current design and permit the use of the RICT Program. Actions b and c also provide the option to use the RICT Program as modified by note #. Under the new design, the coincidence logic is based on two-out-of-four channels and the concept of channels per trip system no longer applies. The existing Actions are no longer appropriate and are replaced. The RICT option is being removed at this time.

The Action b requirement to place the inoperable channels in trip within 12 hours is moved to TS 3.3.1, Action a.1. If the number of channels is insufficient to support the safety function, proposed TS Table 3.3.1-1, Action 11, requires declaring the EOC-RPT subsystems inoperable.

Current TS 3.3.5, Action b, states that when one or more Reactor Core Isolation Cooling (RCIC) actuation instrumentation channels is inoperable, take the Action in Table 3.3.5-1. This requirement is equivalent to proposed TS 3.3.1, Actions a.2 and b.2.

Current TS Table 3.3.5-1, Action 50, requires placing an inoperable channel in the tripped condition within 24 hours or declaring the RCIC system inoperable. This action is incompatible with more restrictive actions applicable to the associated function, "Reactor Vessel Water Level - Low Low, Level 2." Therefore, Action 50 is removed.

Current TS Table 3.3.5-1, Action 51, requires declaring the RCIC system inoperable within 24 hours. This action is incompatible with more restrictive actions applicable to the associated function, "Reactor Vessel Water Level - High, Level 8." Therefore, Action 51 is removed.

Current TS Table 3.3.5-1, Action 52, requires placing an inoperable channel in the tripped condition within 24 hours or declaring the RCIC system inoperable. This action is incompatible with more restrictive actions applicable to the associated function, "Condensate Storage Tank Water Level - Low." Therefore, Action 52 is removed.

Proposed Actions

Proposed TS 3.3.1 contains Actions that reflect the diversity and redundancy of the design. In Operational Conditions 1, 2, or 3, if one of the required channels is inoperable then within 12 hours one of three actions must be taken: place the inoperable channel in trip; initiate the actions for the channel in Table 3.3.1-1, or shutdown the unit. An exception to placing the channels in trip is provided for permissive signals, which must be placed in bypass (i.e., the safe condition for a permissive.) If two of the required channels are inoperable in Operational Conditions 1, 2, or 3, the same actions must be taken within 6 hours. If one required channel is inoperable, the remaining two operable channels provide redundancy to perform the function. Therefore, 12 hours to restore an inoperable channel is appropriate before taking actions. If two required channels are inoperable, the remaining channel can perform the safety function but without redundancy. Therefore, 6 hours to restore the channel is appropriate.

In Operational Condition 4, if one or more required channels are inoperable then within 1 hour all insertable control rods must be inserted and the reactor mode switch must be locked in the Shutdown position. This is comparable to existing Action 2 in current TS Table 3.3.1-1 and provides the appropriate actions for the level of degradation.

In Operational Condition 5, with one or more required channels inoperable, then within 1 hour the inoperable channels must be placed in the tripped condition, or all operations involving Core Alterations must be suspended and all insertable control rods must be inserted. This is comparable to the existing Action 3 in current TS Table 3.3.1-1 and provides the appropriate actions for the level of degradation.

These changes are acceptable because they reflect the system design and revised TS organization and maintain the intent of the existing Actions.

D04

LCOs in current TS 3.3.1, TS 3.3.2, TS 3.3.3, TS 3.3.4.2, and TS 3.3.5 include Channel Checks, Channel Functional Tests, Channel Calibrations, and Logic System Functional Tests on the functions required to be operable, as described in current TS SRs 4.3.1.1, 4.3.1.2, 4.3.2.1, 4.3.2.2, 4.3.3.1, 4.3.3.2, 4.3.5.1, and 4.3.5.2. The applicability to each function and any exceptions to these tests are described in current TS Table 4.3.1.1-1, Table 4.3.2.1-1, and Table 4.3.3.1-1[2]. The requirement to perform Channel Checks, Channel Functional Tests, Channel Calibrations, and Logic System Functional Tests is deleted for the functions that have been incorporated into the PPS and a Sensor Channel Calibration is required.

The existing SRs are retained for the following functions which are not incorporated into the PPS:

- Intermediate Range Monitors
- Average Power Range Monitors
- End of Cycle Recirculation Pump Trip System Instrumentation Functions
- Turbine Stop Valve - Closure and Turbine Control Valve - Fast Closure

The testing of manual initiation functions is discussed in Discussion of Change 06. The testing of Isolation Actuation Instrumentation functions "HPCI Steam Line Δ Press Timer," "RCIC Steam Line Δ Pressure Timer," and "Emergency Core Cooling System Actuation Instrumentation ADS Timer," and "ADS Drywell Pressure Bypass Timer" is discussed in proposed TS 3.3.2. The testing of loss-of-power functions is discussed in proposed TS 3.3.5.

As described in the PPS Licensing Technical Report, the PPS performs a nearly continuous comparison equivalent to the Channel Check. Therefore, a manual Channel Check is not required. The digital platform also performs a frequent test equivalent to the Channel Functional Test. Therefore, a manual Channel Functional Test is not required. As a result, these surveillance requirements are removed.

---

[2] It should be noted that in the Surveillance Requirement tables, the absence of an entry in the Channel Check, Channel Functional Test, or Channel Calibration column indicates that the test is required to be performed at the frequency specified in the Surveillance Frequency Control Program, as indicated in the table notes.

The digital system also performs a frequent test equivalent to a Channel Calibration from the input into the PPS from the sensor to the output to the actuated system. As a result, an "end to end" Channel Calibration is not required. The added Sensor Channel Calibration, which is discussed above in the proposed changes to TS Chapter 1, confirms that the sensor responds with the necessary range and accuracy to known values of the parameter which the channel monitors up to the input to the PPS. The definition of Sensor Channel Calibration also incorporates existing allowances, such exclusion of neutron detectors and other nonadjustable devices, such as digital inputs, thermocouples, and resistance temperature detectors, provided that the remaining adjustable devices in the channel.

The proposed change is acceptable because the automated testing of the functions satisfies the requirements of 10 CFR 50.36(c)(3). The automatic testing of the digital platform will assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

D05
The current TS 3.3.1 Actions are modified by a Note which states, "Separate condition entry is allowed for each channel." This note is revised to state, "Separate condition entry is allowed for each function." Proposed TS Table 3.3.1-1 refers to each item as a "function." IEEE Standard 603, "Criteria for Safety Systems for Nuclear Power Generating Stations," defines a "channel" as "An arrangement of components and modules as required to generate a single protective action signal when required by a generating station condition." In the current LGS TS, redundant and independent channels provide separate protective action signals (i.e., the Minimum Operable Channels requirement). The "protective action signal" provided by the redundant channels is called a "Function" in the proposed TS. The actions in proposed TS 3.3.1 are designed to permit separate condition entry for each Function, and the actions are dependent on the number of inoperable channels for a particular Function. For example, an action may be entered separately for one inoperable channel in the "Drywell Pressure - High" Function and one inoperable channel in the "Turbine Stop Valve - Closure" Function. However, separate entry is not permitted for each of two inoperable "Drywell Pressure - High" channels. Instead, the action for two or more inoperable channels in one or more Functions is entered. This change is acceptable because it reflects the system design and the intended usage of the Actions.

D06
The following manual initiation functions are relocated from the current TS to licensee control, to be controlled under 10 CFR 50.59.

- TS 3.3.1, Function 12, Manual Scram
- TS 3.3.2, Function 1.h, Main Steam Line Isolation, Manual Initiation
- TS 3.3.2, Function 2.c, RHR System Shutdown Cooling Mode Isolation, Manual Initiation
- TS 3.3.2, Function 3.f, Reactor Water Cleanup System Isolation, Manual Initiation

- TS 3.3.2, Function 4.g, High Pressure Coolant Injection System Isolation, Manual Initiation
- TS 3.3.2, Function 5.g, Reactor Core Isolation Cooling System Isolation, Manual Initiation
- TS 3.3.2, Function 6.j, Primary Containment Isolation, Manual Initiation
- TS 3.3.2, Function 7.g, Secondary Containment Isolation, Reactor Enclosure Manual Initiation
- TS 3.3.2, Function 7.h, Secondary Containment Isolation, Refueling Area Manual Initiation
- TS 3.3.3, Function 1.d, Core Spray System, Manual Initiation
- TS 3.3.3, Function 2.e, Low Pressure Coolant Injection Mode of RHR System, Manual Initiation
- TS 3.3.3, Function 3.f, High Pressure Coolant Injection System, Manual Initiation
- TS 3.3.3, Function 4.g, Automatic Depressurization System, Manual Initiation
- TS 3.3.5, Function d, Reactor Core Isolation Cooling System, Manual Initiation

These manual scram or manual initiation functions are not assumed to be operable as an initial condition or credited to mitigate the consequences of any design basis accident or transient. The associated systems are designed to actuate automatically in the case of a DBA or transient and contain redundant and independent subsystems to ensure actuation.

Comparison to the 10 CFR 50.36(c)(2)(ii) Selection Criteria:

1. The manual scram and manual initiation functions are not associated with an instrumentation system that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.
2. The manual scram and manual initiation functions are not a process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or challenge to the integrity of a fission product barrier.

3. The manual scram and manual initiation functions are not credited in the analysis of any design basis accident or transient. This criterion only applies to structures, systems, or components that are part of the primary success path, which consists of the combination and sequences of equipment needed to operate (including consideration of the single failure criteria), so that the plant response to design basis accidents and transients limits the consequences of these events to within the appropriate acceptance criteria. The primary success path does not include backup and diverse equipment. The manual scram and manual initiation functions are not a structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.
4. The manual scram and manual initiation functions were found to be non-significant risk contributors to core damage frequency and offsite releases, consistent with the Commission's Safety Goal and Severe Accident Policies, and operational experience has shown that the manual scram and manual initiation functions are not a constraint of prime importance in limiting the likelihood or severity of the accident sequences that dominate risk. Therefore, the manual scram and manual initiation functions do not represent structures, systems, or components which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

Because the selection criteria have not been satisfied, the manual scram and manual initiation functions may be relocated to licensee-controlled documents outside the Technical Specifications. Any future changes to these requirements will be evaluated under 10 CFR 50.59. Testing of these functions will be performed as required by the Quality Assurance Program.

D07
Current TS Table 3.3.1-1, Functional Unit 1, "Intermediate Range Monitors," lists the Minimum Channels Per Trip System as three. In Operational Condition 5, the minimum number of channels per trip system is modified by Note (d), which states:

> "The noncoincident NMS reactor trip function logic is such that all channels go to both trip systems. Therefore, when the 'shorting links' are removed, the Minimum OPERABLE Channels Per Trip System is 6 IRMs."

The current TS Table 4.3.1.1-1 Channel Function Test requirement for the IRM Functional Units is modified by Note (j) which states:

> "If the RPS shorting links are required to be removed per Specification 3.9.2, they may be reinstalled for up to 2 hours for required surveillance. During this time, CORE ALTERATIONS shall be suspended, and no control rod shall be moved from its existing position."

In the proposed TS, the minimum number of channels is changed to six, and Notes (d) and (j) are deleted.

As described in Discussion of Change 10, the coincidence logic is changed and the concept of two trip systems is no longer applicable to the IRM function. As a result, the minimum number of channels is six, consistent with the current requirement of three channels in both trip systems. Note (d) discusses the use of "shorting links" which are used in Operational Condition 5 to align all IRMs to both trip systems. The Note indicates that when the "shorting links" are removed, the minimum number of channels is six. As the proposed TS will require six IRMs at all times, the Note is no longer required and is removed.

Table 4.3.1.1-1 Note (j) provides an allowance for manually performing a Channel Functional Test. As described in Discussion of Change 4, manual Channel Functional Tests are removed as equivalent testing is performed by the PPS. Therefore, Note (j) is no longer required and it is removed. These changes are acceptable because they reflect the new design.

D08

Current TS Table 3.3.1-1, "Reactor Protection System Instrumentation," Function 2, "Average Power Range Monitor," states that the Minimum Operable Channels per Trip System is three (except for function 2.e, "2-Out-Of-4 Voter"), as modified by Note (m). Note (m) states: "Each APRM channel provides inputs to both trip units." In the proposed TS, Note (m) is deleted.

As described in Discussion of Change 10, the coincidence logic is changed and the concept of two trip systems is no longer applicable to the APRM function. The table column is renamed from "Minimum Operable Channels per Trip System" to "Minimum Operable Channels." However, given that Note (m) states that each APRM channel provides inputs to both trip units, the number of required channels remains as "3." Note (m) is no longer required and is deleted. These changes are acceptable because they reflect the new design.

D09

The existing TSs contain the following information that is included as an operator aid but that is not part of the TS requirements:

- Current TS Table 3.3.1-1, Function 9, "Turbine Stop Valve - Closure," and Function 10, "Turbine Control Valve Fast Closure, Trip Oil Pressure - Low," are modified by Note (k) which states, "Also actuates the EOC RPT System."
- Current TS Table 2.2.1-1, Note * states, "See Bases Figure B 3/4.3-1" and Note ** states, "Equivalent to 25.45 gallons/discharge volume." These notes are associated with trip setpoints but are also descriptive of the allowable values.

- Current TS Table 3.3.2-1, "Isolation Actuation Instrumentation," lists the isolation signal associated with each Function. This column is deleted and the information is moved to the TS Bases.
- Current TS Table 4.3.2.1-1, Note ## states, "These trip functions (2a, 6b, and 7b) are common to the RPS actuation trip function."
- Current TS Table 3.3.2-2, Note * states, "See Bases Figure B 3/4.3-1." This note is associated with trip setpoints but is also descriptive of the allowable values.
- Table 3.3.3-1, Note (b) states, "Also provides input to actuation logic for the associated emergency diesel generators."
- Table 3.3.3-1, Note (e) states, " The manual initiation push buttons start the respective core spray pump and diesel generator. The "A" and "B" logic manual push buttons also actuate an initiation permissive in the injection valve opening logic."
- Table 3.3.3-2, Note * states, "See Bases Figure B 3/4.3-1." This note is associated with trip setpoints but is also descriptive of the allowable values.
- Table 3.3.5-2, Note * states, "See Bases Figure B 3/4.3-1" and Note ** states, "Corresponds to 2.3 feet indicated." These notes are associated with trip setpoints but are also descriptive of the allowable values.

These notes are removed from the TS and placed in the TS Bases. These Notes do not represent TS requirements and are provided as an operator aid. As such, they should be located in the TS Bases. This change is acceptable because it is consistent with the 10 CFR 50.36 descriptions of the purpose of TS and TS Bases.

D10

Current TS 3.3.1, Table 3.3.1-1, TS 3.3.2, Table 3.3.2-1, TS 3.3.3, Table 3.3.3-1[3], TS 3.3.4.2, Table 3.3.4.2-1, TS 3.3.5 and Table 3.3.5-1 refer to trip systems, and the tables contain a column labeled, "Minimum Operable Channels per Trip System." Various Notes refer to "trip systems." In the proposed TS, the table column is relabeled "Minimum Operable Channels," and the entries for the Functions in the tables are revised to reflect the new design. Notes that are based on "trip systems" are revised or deleted.

[3] Table 3.3.3-1 contains a column labeled, "Minimum Operable Channels per Trip Function," but all functions except for High pressure Coolant Injection System are modified by a Note that states, "The Minimum OPERABLE Channels Per Trip Function is per subsystem."

As discussed in Section 3.2.2 of the PPS Licensing Technical Report and Sections 5.1 through 5.3 of WNA-DS-04899-GLIM, "Limerick Generating Station Plant Protection System Digital Modernization Project System Requirement Specification" (LGS PPS SyRS) (i.e., Attachment 6 to this LAR), the instrumentation coincidence logic for most PPS Functions is changed from "one-out-of-two-taken-twice" to "two-out-of-four," and the terminology, "channels per trip systems," is no longer applicable under the new design. As a result, the minimum number of channels required to perform the safety function is revised in the proposed TS.

For most functions, less than the full complement of installed channels are required to be operable to perform the safety function. As a result, most channel testing can be performed without declaring a channel inoperable. Therefore, notes that permit a channel to be placed in an inoperable status for a specified period for required surveillance without placing the trip system in the tripped condition are no longer needed and are removed except for the Functions in which all the channels are required.

The proposed changes are acceptable because they reflect the new design.

D11

The instrumentation channel functions in current TSs 2.2.1, 3.3.1, 3.3.2, 3.3.3, 3.3.4.2, and 3.3.5 are combined into the proposed TS 3.3.1, "Plant Protection System Instrumentation Channels." In some cases, the Applicable Operational Conditions and associated Notes for the same function differed between specifications. The Operational Conditions are revised to be consistent, and the Notes are revised to support the combination.

- Proposed TS Table 3.3.1-1, Function 5.a, "Reactor Vessel Water level - Low, Level 3" is made applicable in Operational Conditions 1, 2, and 3, combining the applicable conditions from current TS Table 3.3.1-1 (Operational Conditions 1 and 2) and current TS Tables 3.3.2-1 and 3.3.3-1 (Operational Conditions 1, 2, and 3).
- Proposed TS Table 3.3.1-1, Function 8, "Drywell Pressure – High" is made applicable in Operational Conditions 1, 2, and 3, combining the applicable conditions from current TS Table 3.3.1-1 (Operational Conditions 1and 2) and current TS 3.3.5 (Operational Conditions 1, 2, and 3).

These changes are appropriate because they reflect the operational conditions under which the Functions are required to be operable.

D12

Current TS Table 4.3.1.1-1, Function 2.b, "Average Power Range Monitor, Simulated Thermal Power - Upscale," SR Chanel Calibration, is modified by Note (o) which states, "If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service," and Note (p) which states, "The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Trip Setpoint at the completion of the surveillance; otherwise, the channel shall be declared inoperable.

Setpoints more conservative than the Trip Setpoint are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the surveillance procedures (field setting) to confirm channel performance.

The methodologies used to determine the as-found and the as-left tolerances are specified in the associated Technical Specifications Bases." These notes are deleted and do not appear in the proposed TS.

Notes (o) and (p) are applied to a single Function in the LGS TS. The purpose of the Notes is to clarify that operability requirements for the channels. These Notes were added to address an NRC staff concern discussed in Regulatory Issue Summary (RIS) 2006-17, "NRC Staff Position on The Requirements Of 10 CFR 50.36, 'Technical Specifications,' Regarding Limiting Safety System Settings During Periodic Testing and Calibration of Instrument Channels." In 2019, the NRC agreed that adding the footnotes to the plant TS was not necessary if control of as-left and as-found tolerances is being addressed in plant procedures in a manner consistent the notes.

CEG has implemented control of as-left and as-found values in LGS plant procedures consistent with Notes (o) and (p) for all TS setpoints and, therefore, it is not necessary to continue to include these Notes in the TS for this Function. Further, including these Notes only on function 2.b is unnecessary, as the practices are appropriate for all Functions. Therefore, these Notes are not required and are removed.

D13

Current TS Table 4.3.1.1-1, Function 2.b, "Simulated Thermal Power - Upscale," SR Channel Calibration is modified by Notes (d) and (g). Function 2.c, "Neutron Flux - Upscale," is modified by Note (d). Function 2.g, "OPRM Upscale, Channel Calibration" is modified by Note (g). Note (d) states, "The more frequent calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED THERMAL POWER. Verify the calculated power does not exceed the APRM channels by greater than 2% of RATED THERMAL POWER." Note (g) states, "The less frequent calibration includes the flow input function." Note (d) is revised to eliminate the phrase, "more frequent" and Note (g) is deleted.

The phrase, "more frequent" calibration in Note (d) and Note (g) modify the frequency at which the Channel Calibration is performed. Limerick relocated the Surveillance frequencies to the SFCP. Therefore, the phrase in Note (d) and Note (g) are relocated to the SFCP. This change is acceptable because it is consistent with the previous approval to relocate the surveillance frequencies to the Surveillance Frequency Control Program.

D14
Current TS Table 3.3.1-1, Function 2.e, "APRM 2-Out-of-4 Voter," Minimum Operable Channels per Trip System is changed from 2 to four.

There are two trip systems, requiring a total of 4 voter channels. As stated in the existing Bases, "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."

Therefore, under the new design and the new Table heading of "Minimum Operable Channels," four voter channels are required.

D15
Current TS Table 3.3.2-1 room temperature monitoring channels for four Functions are revised to state the minimum operable channel requirements in terms of monitors per zone or the total number of required monitors. This results in the following changes to the Minimum Operable Channels:

- Function 3.b, "Reactor Water Cleanup System (RWCS) Area Temperature – High" is changed from 6 to 12.
- Function 3.c, "RWCS Area Ventilation Δ Temperature – High" is changed from 6 to 12.
- Function 5.f, "Reactor Core Isolation Cooling (RCIC) Pipe Routing Area Temperature – High" is changed from 5 to 10.

As discussed in Section 3.2.2 of the PPS Licensing Technical Report and Sections 5.1 through 5.3 of the LGS PPS SyRS (i.e., Attachment 7 to this LAR), the instrumentation coincidence logic for most PPS Functions is changed from "one-out-of-two-taken-twice" to "two-out-of-four," and the terminology, "channels per trip systems," is no longer applicable under the new design. As a result, the minimum number of channels required to perform the safety function is revised in the proposed TS. The proposed changes are acceptable because it reflects the new design.

D16
The Reactor Vessel Pressure - Low permissive functions in current TS Table 3.3.2-2, Function 1.c (Core Spray System) and Function 2.c (Low Pressure Coolant Injection Mode of RHR), are combined in proposed TS Table 3.3.1-1 as Function 3.c, "Reactor Vessel Pressure - Low", subpart 1, "LOCA (Permissive)," and subpart 2, "Core Spray (Permissive)."

The LOCA (Permissive) requires a minimum of 3 channels and the Core Spray (Permissive) requires a minimum of four channels. If the Core Spray (Permissive) is inoperable, Action 17 requires the inoperable channel to be placed in bypass within 1 hour and to restore the inoperable channel within 7 days. With the number of operable channels two or more less than the Minimum Operable Channels, Action 17 requires declaring the Core Spray System inoperable within 24 hours.

Placing the permissive channels in bypass instead of trip is appropriate because a trip signal would indicate that the desired conditions are met, which may not be the case. Placing the channel in bypass results in relying on the operable channels to indicate the plant condition. The Core Spray (Permissive) requires 4 channels to be operable under the design due to the postulated failure modes. This combination of Functions and the corresponding Action are appropriate because they reflect the plant design.

D17

The current Action for an inoperable channel of Reactor Vessel Water Level - High, Level 8 in current TS Table 3.3.3-1, Function 3.e (HPCI System), and current TS Table 3.3.5-1, Function b (RCIC System), is to declare the associated system inoperable within 24 hours. These Actions are replaced with new Action 18, which placing a single required inoperable channel in bypass within 1 hour and restore the inoperable channel within 7 days. With the number of operable channels two or more less than the Minimum Operable Channels, Action 18 requires placing one inoperable channel in bypass and the remaining inoperable channels in the trip condition within 1 hour, and to restore the inoperable channels within 7 days.

The proposed Action reflects that four channels of the Level 8 Function are required. If one channel is inoperable, it is necessary to place the channel in bypass to ensure the remaining channels can perform the Function. Subsequent inoperable channels must be placed in the trip condition to ensure the safety function can be performed. The proposed change is acceptable because it reflects the plant design.

D18

The Automatic Depressurization System (ADS) permissive functions in current TS Table 3.3.3-1, Function 4.d, "Core Spray Pump Discharge Pressure - High (Permissive)," and 4.e, " RHR LPCI Mode Pump Discharge Pressure High (Permissive)," are combined into proposed TS Table 3.3.1-1, Function 11, "Automatic Depressurization System (Permissives)." The Allowable Values and Applicabilities are unchanged. The Minimum Operable Channels is six. A new Action 18 is added which applies when the ADS permissive Function is inoperable.

The Action requires placing one inoperable channel in bypass within 1 hour and restoring the inoperable channel within 7 days. With the number of operable channels two or more less than the Minimum Operable Channels, the Action requires placing one inoperable channel in bypass and the remaining inoperable channels in the trip condition within 1 hour, and to restore the inoperable channels within 7 days. Current TS 3.3.3, Action c, which is applicable when either ADS trip system is inoperable, is removed and the appropriate requirements and Actions for inoperable ADS actuation initiation are added to TS 3.5.1.

The change in the required number of channels is necessary to ensure that a single failure will not prevent the performance of the safety function. The Core Spray System and RHR Low Pressure Coolant Injection System are fully redundant and credited makeup sources for ADS blowdown. Any one of the 6 required channels is sufficient to support blowdown and reflood. The proposed changes are acceptable because they reflect the plant design and accident analysis assumptions.

Unit 1

Proposed Technical Specifications

3/4.3 INSTRUMENTATION

3/4.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

LIMITING CONDITION FOR OPERATION

3.3.1 The plant protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

Note: Separate condition entry is allowed for each Function.

a. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions one less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 12 hours:

   1. Place the required inoperable channel in the tripped condition#, or

   2. Initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

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

b. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions two or more less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 6 hours:

   1. Place the required inoperable channels in the tripped condition#, or

   2. Place one required inoperable channel in the trip condition# and initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

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

c. In OPERATIONAL CONDITION 4, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour verify all insertable control rods to be inserted in the core* and lock the reactor mode switch in the Shutdown position within 1 hour.

d. In OPERATIONAL CONDITION 5, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour place the inoperable channels in the tripped condition, or within 1 hour suspend all operations involving CORE ALTERATIONS and insert all insertable control rods*.

----

* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

For permissive Functions 3.c.2, 4.c, 11, and 12, Actions a.1 and b.1 are not applicable. For these functional units inoperable channel(s) shall be placed in bypass instead of trip to comply with Action b.2.

CTS

3/4.3 INSTRUMENTATION

3/4.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each plant protection system instrumentation channel except for Function 1, "Intermediate Range Monitors," and Function 2, "Average Power Range Monitors," shall be demonstrated OPERABLE by the performance of a SENSOR CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.1, Note (b) 4.3.1.2 The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.

4.3.1.1 4.3.1.3 Each IRM Neutron Flux - High channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCITONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Neutron detectors may be excluded from CHANNEL CALIBRATION.

4.3.1.1 4.3.1.4 Each IRM Inoperative channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.1 4.3.1.5 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale, Neutron Flux - Upscale, 2-Out-Of-4 Voter, and OPRM Upscale function shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.1 4.3.1.6 Each APRM Neutron Flux - Upscale (Setdown)*, Simulated Thermal Power - Upscale**, Neutron Flux - Upscale, Inoperative, 2-Out-Of-4 Voter, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.1, Note (c) 4.3.1.7 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale***, Neutron Flux - Upscale***, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Calibration includes verification that the OPRM Upscale trip auto-enable (not-bypass) setpoint for APRM Simulated Thermal Power is ≥ 29.5% and for recirculation drive flow is < 60%.

4.3.1.1, Note(f) 4.3.1.8 The APRM LPRM inputs shall be calibrated at least once per 2000 effective full power hours (EFPH).

4.3.4.2.2 4.3.1.9 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of the Turbine Stop Valve - Closure and the Turbine Control Valve - Fast Closure End-of-Cycle Recirculation Pump Trip System Functions shall be performed in accordance with the Surveillance Frequency Control Program.

4.3.1.1, Note * — * Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

4.3.1.1, Note (e) — ** The CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.

4.3.1.1, Note (d) — *** Calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED THERMAL POWER. Verify the calculated power does not exceed the APRM channels by greater than 2% of RATED THERMAL POWER.

INTENTIONALLY LEFT BLANK

TABLE 3.3.1-1

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

CTS/Function	FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
	Neutron Flux				
3.3.1/1	1. Intermediate Range Monitors[a]				
	a. Neutron Flux - High	2	6	≤ 122/125 divisions of full scale	
		3[f]	6	≤ 122/125 divisions of full scale	2, 15
		4[f], 5[f]	6	≤ 122/125 divisions of full scale	
	b. Inoperative	2 3[f] 4[f], 5[f]	6	N.A.	2, 15
3.3.1/2	2. Average Power Range Monitor[b]				
	a. Neutron Flux - Upscale (Setdown)	2	3	≤ 20.0% of RATED THERMAL POWER	
	b. Simulated Thermal Power - Upscale				14
	i. Two Recirculation Loop Operation	1	3	≤ 0.65 W + 62.2% and ≤ 117.0% of RATED THERMAL POWER	
	ii. Single Recirculation Loop Operation[e]	1	3	≤ 0.65 (W–7.6%) + 62.0% and ≤117.0% of RATED THERMAL POWER	
	c. Neutron Flux - Upscale	1	3	118.7% of RATED THERMAL POWER	14
	d. Inoperative	1,2	3	N.A.	
	e. 2-Out-Of-4 Voter	1,2	4[r]	N.A.	
	f. OPRM Upscale	1[c][d]	3	N.A.	12
	3. Reactor Vessel Pressure				
3.3.1/3	a. Reactor Vessel Steam Dome Pressure - High	1, 2[k]	3	≤ 1103 psig	
3.3.2/2.b	b. Reactor Vessel Pressure - High (RHR-SDC Cut-In)	1,2,3	3	≤ 95 psig	4
3.3.3/1.c, 2.c	c. Reactor Vessel Pressure - Low				
	1. LOCA (Permissive)	1,2,3	3	≥ 435 psig (decreasing)	
	2. Core Spray (Permissive)	1,2,3	4	≥ 435 psig (decreasing)	17
3.3.2/4.b	d. HPCI Steam Supply Pressure - Low	1,2,3	3	≥ 90 psig	4
3.3.2/5.b	e. RCIC Steam Supply Pressure - Low	1,2,3	3	≥ 56.5 psig	4
3.3.2/6.a	4. Reactor Vessel Water Level - Wide Range				
3.3.2/1.a.2)	a. Low, Low, Low Level 1	1,2[n],3[n]	3	≥ - 136 inches	
3.3.2/1.a.1)	b. Low, Low - Level 2	1,2[o][q],3[o][q]	3	≥ - 45 inches	
3.3.2/3.e 3.3.2/6.h 3.3.2/7.a 3.3.3/1.a, 2.a, 3.a 4.a 3.3.3/3.f 3.3.5/a, b	c. High, Level 8	1,2[o][q],3[o][q]	4[r]	≤ 60 inches	18

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

CTS/Function	FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
3.3.1/4 3.3.2/2a 3.3.3/4.f	5. Reactor Vessel Water Level - Narrow Range				
	a Low - Level 3	$1,2^{(n)},3^{(n)(q)}$	3	≥ 11.0 inches	
	Reactor Trip System				
3.3.1/8	6. Scram Discharge Volume Water Level - High				
	a. Level Transmitter	$1,2,5^{(f)}$	3	≤ 261' 5 5/8" elevation	
	b. Float Switch	$1,2,5^{(f)}$	3	≤ 261' 5 5/8" elevation	
3.3.1/11	7. Reactor Mode Switch Position	1,2, 3,4, 5	3	N.A.	 15 16
	Drywell				
3.3.1/7 3.3.2/6.b 3.3.2/6.h	8. Drywell Pressure - High	$1^{(p)},2^{(n)(o)(p)(s)},$ $3^{(n)(o)(p)}$	3	≤ 1.88 psig	
3.3.2/7.b 3.3.3/1.b, 2.b, 3.b, 4.b 3.3.2/6.i	9. Primary Containment Instrument Gas Line to Drywell Δ Pressure - Low	1,2,3	1/valve	≥ 1.9 psi	5
	Emergency Core Cooling System				
3.3.3/3.c 3.3.5/c	10. Condensate Storage Tank Level - Low	$1,2^{(o)},3^{(o)(q)}$	3	≥ 164.3 inches, ≥ 132.2 inches$^{(t)}$	13
3.3.3/4.d,4.e	11. Automatic Depressurization System (Permissives)	$1,2^{(n)},3^{(n)}$	6	≥ 125 psig, (increasing), ≥ 115 psig, (increasing) $^{(u)}$	10
3.3.3/2.d	12. LPCI Injection Valve Differential Pressure-Low (Permissive)	1,2,3	1/valve	≥ 64 psid and ≤ 84 psid	7
	High Pressure Coolant Injection (HPCI)				
3.3.3/3.d	13. Suppression Pool Water Level - High	$1,2^{(o)},3^{(o)}$	$2^{(r)}$	≤ 24 feet 3 inches	8
3.3.2/4a	14. HPCI Steam Line Δ Pressure - High	1,2,3	$2^{(r)}$	≤ 984" H_20	4
3.3.2/4.c	15. HPCI Turbine Exhaust Diaphragm Pressure - High	1,2,3	3	≤ 20 psig	4
3.3.2/4.d	16. HPCI Equipment Room Temperature - High	1,2,3	$2^{(r)}$	≥ 177°F, ≤ 191°F	4
3.3.2/4.e	17. HPCI Equipment Room Δ Temperature High	1,2,3	$2^{(r)}$	≤ 108.5°F	4
3.3.2/4.f	18. HPCI Pipe Routing Area Temperature - High	1,2,3	8	≥ 177°F, ≤ 191°F	4

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

CTS/Function	FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
	Main Steam, Turbine, Condenser				
3.3.1/5	19. Main Steam Line Isolation Valve - Closure	1(g)	3	≤ 12% closed	14
3.3.1/9 3.3.4.2/1	20. Turbine Stop Valve - Closure	1(h)	3	≤7% closed	1, 11
3.3.1/10 3.3.4.2/2	21. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	1(h)	3	≥ 465 psig	1, 11
3.3.2/1.c	22. Main Steam Line Pressure - Low	1	3	≥ 821 psig	14
3.3.2/1.d	23. Main Steam Line Flow - High	1,2,3	3/steam line	≤ 123 psid	
3.3.2/1.e	24. Condenser Vacuum - Low	1,2(i),3(i)	3	≥10.1 psia/≤ 10.9 psia	3
3.3.2/1.f	25. Outboard MSIV Room Temperature - High	1,2,3	3	≤ 200°F(l)	3
	Reactor Water Cleanup System and Standby Liquid Control				
3.3.2/3.a	26. RWCS Δ Flow - High	1,2,3	2(r)	≤ 65.2 gpm	4
3.3.2/3.b	27. RWCS Area Temperature - High	1,2,3	12	≤ 160°F or ≤ 125°F(j)	4
3.3.2/3.c	28. RWCS Area Ventilation Δ Temperature - High	1,2,3	12	≤ 60°F or ≤ 40°F(j)	4
3.3.2/3.d	29. SLCS Initiation	1,2,3	N.A.	N.A.	4
	Reactor Core Isolation Cooling (RCIC)				
3.3.2/5.a	30. RCIC Steam Line Δ Pressure - High	1,2,3	2(r)	≤ 381" H_2O	4

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

CTS/Function	FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
	Reactor Core Isolation Cooling (RCIC) (Continued)				
3.3.2/5.c	31. RCIC Turbine Exhaust Diaphragm Pressure - High	1,2,3	3	≤ 20.0 psig	4
3.3.2/5.d	32. RCIC Equipment Room Temperature - High	1,2,3	2[(r)]	≥ 161°F, ≤ 191°F	4
3.3.2/5.e	33. RCIC Equipment Room Δ Temperature - High	1,2,3	2[(r)]	≤ 113.5°F	4
3.3.2/5.f	34. RCIC Pipe Routing Area Temperature - High	1,2,3	10	≥ 161°F, ≤ 191°F	4
	Radiation Monitoring				
3.3.2/6.c	35. North Stack Effluent Radiation - High[(m)]	1,2,3	2	≤ 4.0 μCi/cc	4
3.3.2/6.e 3.3.2/7.d	36. Reactor Enclosure Ventilation Exhaust Duct-Radiation - High	1,2,3	3	≤ 1.5 mR/h	6
3.3.2/7.C.1	37. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	Required when handling RECENTLY IRRADIATED FUEL in the secondary containment and during operation of the associated Unit 1 or Unit 2 ventilation exhaust system.	3	≤ 2.2 mR/h	6
3.3.2/7.C.2	38. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	Required when handling RECENTLY IRRADIATED FUEL in the secondary containment and during operation of the associated Unit 1 or Unit 2 ventilation exhaust system.	3	≤ 2.2 mR/h	6

TABLE 3.3.1-1 (Continued)

CTS Table/Action

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

ACTION STATEMENTS

CTS Table/Action		
3.3.1-1/6	ACTION 1 -	Initiate a reduction in THERMAL POWER within 15 minutes and reduce turbine first stage pressure until the function is automatically bypassed, within 2 hours.
3.3.1-1/8	ACTION 2 -	Lock the reactor mode switch in the Shutdown position within 1 hour.
3.3.2-1/21	ACTION 3 -	Be in at least STARTUP with the associated penetration flow path(s) isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 6 hours.
3.3.2-1/23	ACTION 4 -	In OPERATIONAL CONDITION 1 or 2, verify the affected penetration flow path(s) are isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour and declare the affected system inoperable. In OPERATIONAL CONDITION 3, be in at least COLD SHUTDOWN within 12 hours.
3.3.2-1/26	ACTION 5 -	Isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour.
3.3.2-1/25	ACTION 6 -	Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.
3.3.3-1/31	ACTION 7 -	Declare the associated ECCS inoperable within 24 hours.
3.3.3-1/35	ACTION 8 -	Declare the HPCI System Inoperable if reactor steam dome pressure if > 200 psig.
3.3.5-1/e	ACTION 9 -	Declare the RCIC System Inoperable if reactor steam dome pressure is > 150 psig.
	ACTION 10 -	Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 5 channels to OPERABLE status within 14 days. With one or less OPERABLE channels, declare the Automatic Depressurization System inoperable.
3.3.4.2/e	ACTION 11 -	With the number of OPERABLE channels 2 or more less than the Minimum OPERABLE channels, declare both End-of-Cycle - Recirculation Pump Trip subsystems inoperable.
	ACTION 12 -	If all OPRM Upscale channels are inoperable due to a common mode OPRM deficiency, initiate an alternate method to detect and suppress thermal-hydraulic instability oscillations within 12 hours and restore required channels to OPERABLE status within 120 days. Otherwise, reduce THERMAL POWER to < 25% RATED THERMAL POWER within 4 hours.
	ACTION 13 -	Align the affected system to a safety-related source.
	ACTION 14 -	Be in at least STARTUP within 6 hours.
	ACTION 15 -	Verify all insertable control rods to be inserted within 1 hour.
	ACTION 16 -	Suspend all operations involving CORE ALTERATIONS and insert all insertable control rods within 1 hour.
	ACTION 17 -	Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 3 channels to OPERABLE status within 7 days. With the number of OPERABLE channels three or more less than the Minimum Operable Channels, within 24 hours declare the Core Spray System inoperable.

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

CTS Table/Action

ACTION STATEMENTS

ACTION 18 - Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 3 channels to OPERABLE status within 7 days. With the number of OPERABLE channels three or more less than the Minimum Operable Channels, be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

3.3.2-1/Note *** *** Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.

TABLE 3.3.1-1 (Continued)

CTS Table/Note

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE NOTATIONS

CTS Table/Note		
3.3.1/b	(a)	This function shall be automatically bypassed when the reactor mode switch is in the Run position.
3.3.1/e 3.3.1/Action Note	(b)	An APRM channel is inoperable if there are less than 3 LPRM inputs per level or less than 20 LPRM inputs to an APRM channel, or if more than 9 LPRM inputs to the APRM channel have been bypassed since the last APRM calibration (weekly gain calibration). While operating at ≥ 25% of RATED THERMAL POWER, if one or more APRM channels are inoperable due to calculated power exceeding the APRM output by more than 2% of RATED THERMAL POWER, entry into the associated Actions may be delayed up to 2 hours.
4.3.1.1/c 3.3.1-1/o	(c)	With THERMAL POWER ≥ 25% RATED THERMAL POWER. The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60%. The OPRM trip output may be automatically bypassed when APRM Simulated Thermal Power is < 29.5% or recirculation drive flow is ≥ 60%.
3.3.1/p	(d)	A minimum of 23 cells, each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for an OPRM channel to be OPERABLE.
2.2.1/*** 3.3.1/*	(e)	The 7.6% flow “offset” for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero. The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.
3.3.1/i	(f)	With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.
3.3.1/g	(g)	This function shall be automatically bypassed when the reactor mode switch is not in the Run position.
3.3.1/j	(h)	This function shall be automatically bypassed when turbine first stage pressure is equivalent to a THERMAL POWER of less than 29.5% of RATED THERMAL POWER.
3.3.2-1/**	(i)	May be bypassed under administrative control, with all turbine stop valves closed.
3.3.2-2/**	(j)	The low values are for the RWCU Heat Exchanger Rooms; the high values are for the pump rooms.
4.3.1.1/f	(k)	This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.
3.3.2-1/f	(l)	In the event of a loss of ventilation, the setpoint may be raised by 50°F for a period not to exceed 30 minutes to permit restoration of the ventilation flow without a spurious trip. During the 30 minute period, an operator, or other qualified member of the technical staff, shall observe the temperature indications continuously, so that, in the event of rapid increases in temperature, the main steam lines shall be manually isolated.
3.3.1-1/g	(m)	Wide range accident monitor per Specification 3.3.7.5.
3.3.3-1/#	(n)	The Automatic Depressurization System Initiation Function is only required to be OPERABLE when reactor steam dome pressure is ≥ 100 psig.
3.3.3-1/##	(o)	The High Pressure Coolant Injection System initiation functions are only required to be OPERABLE when reactor steam dome pressure is ≥ 200 psig.
3.3.3-1/ ###	(p)	The High Pressure Coolant Injection System initiation function for Drywell Pressure - High is not required to be OPERABLE when reactor steam dome pressure is < 550 psig.
3.3.5 Appl	(q)	The Reactor Core Isolation Cooling System initiation functions are only required to be OPERABLE when reactor steam dome pressure is > 150 psig.
3.3.1-1/a	(r)	A required channel may be placed in bypass for up to 6 hours for surveillance testing provided at least one OPERABLE channel for the same function is monitoring that parameter and is capable of completing its safety function.

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

CTS Table/Note

TABLE NOTATIONS

3.3.1-1/h (s) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(t) The higher Allowable Value is for OPERABILITY of the High Pressure Coolant Injection System. The lower Allowable Value is for OPERABILITY of the Reactor Core Isolation Cooling System.

(u) The higher Allowable Value is for the OPERABILITY of the Core Spray Pump Discharge Pressure - High Permissive. The lower Allowable Value is for OPERABILITY of the RHR LPCI Mode Pump Discharge Pressure - High Permissive.

Unit 2

Proposed Technical Specifications

See Unit 1 Markup for CTS References

3/4.3 INSTRUMENTATION

3/4.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

LIMITING CONDITION FOR OPERATION

3.3.1 The plant protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

Note: Separate condition entry is allowed for each Function.

a. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions one less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 12 hours:

   1. Place the required inoperable channel in the tripped condition#, or

   2. Initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

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

b. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions two or more less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 6 hours:

   1. Place the required inoperable channels in the tripped condition#, or

   2. Place one required inoperable channel in the trip condition# and initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

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

c. In OPERATIONAL CONDITION 4, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour verify all insertable control rods to be inserted in the core* and lock the reactor mode switch in the Shutdown position within 1 hour.

d. In OPERATIONAL CONDITION 5, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour place the inoperable channels in the tripped condition, or within 1 hour suspend all operations involving CORE ALTERATIONS and insert all insertable control rods*.

----

* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

For permissive Functions 3.c.2, 4.c, 11, and 12, Actions a.1 and b.1 are not applicable. For these functional units inoperable channel(s) shall be placed in bypass instead of trip to comply with Action b.2.

3/4.3 INSTRUMENTATION

3/4.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each plant protection system instrumentation channel except for Function 1, "Intermediate Range Monitors," and Function 2, "Average Power Range Monitors," shall be demonstrated OPERABLE by the performance of a SENSOR CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.2 The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.

4.3.1.3 Each IRM Neutron Flux - High channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCITONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Neutron detectors may be excluded from CHANNEL CALIBRATION.

4.3.1.4 Each IRM Inoperative channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.5 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale, Neutron Flux - Upscale, 2-Out-Of-4 Voter, and OPRM Upscale function shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.6 Each APRM Neutron Flux - Upscale (Setdown)*, Simulated Thermal Power - Upscale**, Neutron Flux - Upscale, Inoperative, 2-Out-Of-4 Voter, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.7 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale***, Neutron Flux - Upscale***, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Calibration includes verification that the OPRM Upscale trip auto-enable (not-bypass) setpoint for APRM Simulated Thermal Power is ≥ 29.5% and for recirculation drive flow is < 60%.

4.3.1.8 The APRM LPRM inputs shall be calibrated at least once per 2000 effective full power hours (EFPH).

4.3.1.9 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of the Turbine Stop Valve - Closure and the Turbine Control Valve - Fast Closure End-of-Cycle Recirculation Pump Trip System Functions shall be performed in accordance with the Surveillance Frequency Control Program.

----

* Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

** The CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.

*** Calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED THERMAL POWER. Verify the calculated power does not exceed the APRM channels by greater than 2% of RATED THERMAL POWER.

INTENTIONALLY LEFT BLANK

TABLE 3.3.1-1

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Neutron Flux				
1. Intermediate Range Monitors[a]				
a. Neutron Flux - High	2	6	≤ 122/125 divisions of full scale	
	3[f]	6	≤ 122/125 divisions of full scale	2, 15
	4[f], 5[f]	6	≤ 122/125 divisions of full scale	
b. Inoperative	2	6	N.A.	
	3[f]			2, 15
	4[f], 5[f]			
2. Average Power Range Monitor[b]				
a. Neutron Flux - Upscale (Setdown)	2	3	≤ 20.0% of RATED THERMAL POWER	
b. Simulated Thermal Power - Upscale				14
i. Two Recirculation Loop Operation	1	3	≤ 0.65 W + 62.2% and ≤ 117.0% of RATED THERMAL POWER	
ii. Single Recirculation Loop Operation[e]	1	3	≤ 0.65 (W–7.6%) + 62.0% and ≤117.0% of RATED THERMAL POWER	
c. Neutron Flux - Upscale	1	3	118.7% of RATED THERMAL POWER	14
d. Inoperative	1,2	3	N.A.	
e. 2-Out-Of-4 Voter	1,2	4[r]	N.A.	
f. OPRM Upscale	1[c][d]	3	N.A.	12
3. Reactor Vessel Pressure				
a. Reactor Vessel Steam Dome Pressure - High	1, 2[k]	3	≤ 1103 psig	
b. Reactor Vessel Pressure - High (RHR-SDC Cut-In)	1,2,3	3	≤ 95 psig	4
c. Reactor Vessel Pressure - Low				
1. LOCA (Permissive)	1,2,3	3	≥ 435 psig (decreasing)	
2. Core Spray (Permissive)	1,2,3	4	≥ 435 psig (decreasing)	17
d. HPCI Steam Supply Pressure - Low	1,2,3	3	≥ 90 psig	4
e. RCIC Steam Supply Pressure - Low	1,2,3	3	≥ 56.5 psig	4
4. Reactor Vessel Water Level - Wide Range				
a. Low, Low, Low Level 1	1,2[n],3[n]	3	≥ - 136 inches	
b. Low, Low - Level 2	1,2[o][q],3[o][q]	3	≥ - 45 inches	
c. High, Level 8	1,2[o][q],3[o][q]	4[r]	≤ 60 inches	18

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
5. Reactor Vessel Water Level - Narrow Range				
a Low - Level 3	$1,2^{(n)},3^{(n)(q)}$	3	≥ 11.0 inches	
Reactor Trip System				
6. Scram Discharge Volume Water Level - High				
a. Level Transmitter	$1,2,5^{(f)}$	3	≤ 261' 5 5/8" elevation	
b. Float Switch	$1,2,5^{(f)}$	3	≤ 261' 5 5/8" elevation	
7. Reactor Mode Switch Position	1,2, 3,4, 5	3	N.A.	 15 16
Drywell				
8. Drywell Pressure - High	$1^{(p)},2^{(n)(o)(p)(s)},3^{(n)(o)(p)}$	3	≤ 1.88 psig	
9. Primary Containment Instrument Gas Line to Drywell Δ Pressure - Low	1,2,3	1/valve	≥ 1.9 psi	5
Emergency Core Cooling System				
10. Condensate Storage Tank Level - Low	$1,2^{(o)},3^{(o)(q)}$	3	≥ 164.3 inches, ≥ 132.2 inches$^{(t)}$	13
11. Automatic Depressurization System (Permissives)	$1,2^{(n)},3^{(n)}$	6	≥ 125 psig, (increasing), ≥ 115 psig, (increasing) $^{(u)}$	10
12. LPCI Injection Valve Differential Pressure-Low (Permissive)	1,2,3	1/valve	≥ 64 psid and ≤ 84 psid	7
High Pressure Coolant Injection (HPCI)				
13. Suppression Pool Water Level - High	$1,2^{(o)},3^{(o)}$	$2^{(r)}$	≤ 24 feet 3 inches	8
14. HPCI Steam Line Δ Pressure - High	1,2,3	$2^{(r)}$	≤ 984" H_20	4
15. HPCI Turbine Exhaust Diaphragm Pressure - High	1,2,3	3	≤ 20 psig	4
16. HPCI Equipment Room Temperature - High	1,2,3	$2^{(r)}$	≥ 177°F, ≤ 191°F	4
17. HPCI Equipment Room Δ Temperature High	1,2,3	$2^{(r)}$	≤ 108.5°F	4
18. HPCI Pipe Routing Area Temperature - High	1,2,3	8	≥ 177°F, ≤ 191°F	4

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Main Steam, Turbine, Condenser				
19. Main Steam Line Isolation Valve - Closure	1(g)	3	≤ 12% closed	14
20. Turbine Stop Valve - Closure	1(h)	3	≤7% closed	1, 11
21. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	1(h)	3	≥ 465 psig	1, 11
22. Main Steam Line Pressure - Low	1	3	≥ 821 psig	14
23. Main Steam Line Flow - High	1,2,3	3/steam line	≤ 123 psid	
24. Condenser Vacuum - Low	1,2(i),3(i)	3	≥10.1 psia/≤ 10.9 psia	3
25. Outboard MSIV Room Temperature - High	1,2,3	3	≤ 200°F(i)	3
Reactor Water Cleanup System and Standby Liquid Control				
26. RWCS Δ Flow - High	1,2,3	2(r)	≤ 65.2 gpm	4
27. RWCS Area Temperature - High	1,2,3	12	≤ 160°F or ≤ 125°F(j)	4
28. RWCS Area Ventilation Δ Temperature - High	1,2,3	12	≤ 60°F or ≤ 40°F(j)	4
29. SLCS Initiation	1,2,3	N.A.	N.A.	4
Reactor Core Isolation Cooling (RCIC)				
30. RCIC Steam Line Δ Pressure - High	1,2,3	2(r)	≤ 381" H_2O	4

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Reactor Core Isolation Cooling (RCIC) (Continued)				
31. RCIC Turbine Exhaust Diaphragm Pressure - High	1,2,3	3	$\leq$ 20.0 psig	4
32 RCIC Equipment Room Temperature - High	1,2,3	2[(r)]	$\geq$ 161°F, $\leq$ 191°F	4
33. RCIC Equipment Room Δ Temperature - High	1,2,3	2[(r)]	$\leq$ 113.5°F	4
34. RCIC Pipe Routing Area Temperature - High	1,2,3	10	$\geq$ 161°F, $\leq$ 191°F	4
Radiation Monitoring				
35. North Stack Effluent Radiation - High[(m)]	1,2,3	2	$\leq$ 4.0 μCi/cc	4
36. Reactor Enclosure Ventilation Exhaust Duct-Radiation - High	1,2,3	3	$\leq$ 1.5 mR/h	6
37. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	Required when handling RECENTLY IRRADIATED FUEL in the secondary containment and during operation of the associated Unit 1 or Unit 2 ventilation exhaust system.	3	$\leq$ 2.2 mR/h	6
38. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	Required when handling RECENTLY IRRADIATED FUEL in the secondary containment and during operation of the associated Unit 1 or Unit 2 ventilation exhaust system.	3	$\leq$ 2.2 mR/h	6

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

ACTION STATEMENTS

ACTION 1 - Initiate a reduction in THERMAL POWER within 15 minutes and reduce turbine first stage pressure until the function is automatically bypassed, within 2 hours.

ACTION 2 - Lock the reactor mode switch in the Shutdown position within 1 hour.

ACTION 3 - Be in at least STARTUP with the associated penetration flow path(s) isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 6 hours.

ACTION 4 - In OPERATIONAL CONDITION 1 or 2, verify the affected penetration flow path(s) are isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour and declare the affected system inoperable. In OPERATIONAL CONDITION 3, be in at least COLD SHUTDOWN within 12 hours.

ACTION 5 - Isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour.

ACTION 6 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

ACTION 7 - Declare the associated ECCS inoperable within 24 hours.

ACTION 8 - Declare the HPCI System Inoperable if reactor steam dome pressure if > 200 psig.

ACTION 9 - Declare the RCIC System Inoperable if reactor steam dome pressure is > 150 psig.

ACTION 10 - Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 5 channels to OPERABLE status within 14 days. With one or less OPERABLE channels, declare the Automatic Depressurization System inoperable.

ACTION 11 - With the number of OPERABLE channels 2 or more less than the Minimum OPERABLE channels, declare both End-of-Cycle - Recirculation Pump Trip subsystems inoperable.

ACTION 12 - If all OPRM Upscale channels are inoperable due to a common mode OPRM deficiency, initiate an alternate method to detect and suppress thermal-hydraulic instability oscillations within 12 hours and restore required channels to OPERABLE status within 120 days. Otherwise, reduce THERMAL POWER to < 25% RATED THERMAL POWER within 4 hours.

ACTION 13 - Align the affected system to a safety-related source.

ACTION 14 - Be in at least STARTUP within 6 hours.

ACTION 15 - Verify all insertable control rods to be inserted within 1 hour.

ACTION 16 - Suspend all operations involving CORE ALTERATIONS and insert all insertable control rods within 1 hour.

ACTION 17 - Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 3 channels to OPERABLE status within 7 days. With the number of OPERABLE channels three or more less than the Minimum Operable Channels, within 24 hours declare the Core Spray System inoperable.

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

ACTION STATEMENTS

ACTION 18 - Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 3 channels to OPERABLE status within 7 days. With the number of OPERABLE channels three or more less than the Minimum Operable Channels, be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

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

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE NOTATIONS

(a) This function shall be automatically bypassed when the reactor mode switch is in the Run position.

(b) An APRM channel is inoperable if there are less than 3 LPRM inputs per level or less than 20 LPRM inputs to an APRM channel, or if more than 9 LPRM inputs to the APRM channel have been bypassed since the last APRM calibration (weekly gain calibration). While operating at ≥ 25% of RATED THERMAL POWER, if one or more APRM channels are inoperable due to calculated power exceeding the APRM output by more than 2% of RATED THERMAL POWER, entry into the associated Actions may be delayed up to 2 hours.

(c) With THERMAL POWER ≥ 25% RATED THERMAL POWER. The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60%. The OPRM trip output may be automatically bypassed when APRM Simulated Thermal Power is < 29.5% or recirculation drive flow is ≥ 60%.

(d) A minimum of 23 cells, each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for an OPRM channel to be OPERABLE.

(e) The 7.6% flow "offset" for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero. The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

(f) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(g) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(h) This function shall be automatically bypassed when turbine first stage pressure is equivalent to a THERMAL POWER of less than 29.5% of RATED THERMAL POWER.

(i) May be bypassed under administrative control, with all turbine stop valves closed.

(j) The low values are for the RWCU Heat Exchanger Rooms; the high values are for the pump rooms.

(k) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(l) In the event of a loss of ventilation, the setpoint may be raised by 50°F for a period not to exceed 30 minutes to permit restoration of the ventilation flow without a spurious trip. During the 30 minute period, an operator, or other qualified member of the technical staff, shall observe the temperature indications continuously, so that, in the event of rapid increases in temperature, the main steam lines shall be manually isolated.

(m) Wide range accident monitor per Specification 3.3.7.5.

(n) The Automatic Depressurization System Initiation Function is only required to be OPERABLE when reactor steam dome pressure is ≥ 100 psig.

(o) The High Pressure Coolant Injection System initiation functions are only required to be OPERABLE when reactor steam dome pressure is ≥ 200 psig.

(p) The High Pressure Coolant Injection System initiation function for Drywell Pressure - High is not required to be OPERABLE when reactor steam dome pressure is < 550 psig.

(q) The Reactor Core Isolation Cooling System initiation functions are only required to be OPERABLE when reactor steam dome pressure is > 150 psig.

(r) A required channel may be placed in bypass for up to 6 hours for surveillance testing provided at least one OPERABLE channel for the same function is monitoring that parameter and is capable of completing its safety function.

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE NOTATIONS

(s) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(t) The higher Allowable Value is for OPERABILITY of the High Pressure Coolant Injection System. The lower Allowable Value is for OPERABILITY of the Reactor Core Isolation Cooling System.

(u) The higher Allowable Value is for the OPERABILITY of the Core Spray Pump Discharge Pressure - High Permissive. The lower Allowable Value is for OPERABILITY of the RHR LPCI Mode Pump Discharge Pressure - High Permissive.

Unit 1

Revised Technical Specifications Bases (For Information Only)

~~2.2 LIMITING SAFETY SYSTEM SETTINGS~~

TS Bases 3/4.3.1
Insert 1

BASES

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each parameter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. All four voters will trip (full scram) when any two unbypassed APRM channels exceed their trip setpoints.

APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) scram setting of 15% of RATED THERMAL POWER provides adequate thermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

3/4.3.1 Plant Protection System Instrumentation Channels

This specification provides the limiting conditions for operation necessary to preserve the ability of the systems supported to perform its intended function even during periods when instrument channels may be out of service because of maintenance. For many functions, four channels are provided and only three channels are needed to satisfy the single failure design criteria and to perform the safety function. As a result, one channel may be removed from service to conduct required surveillances.

Instruments associated with reactor trip function meet the requirements of IEEE-279 for nuclear power plant protection systems. Instrument surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and instrument maintenance outage times have been aligned to the system out of service times for the functions they support.

PPS Overview

Collectively, the logic circuits for reactor scram, NSSSS, and ECCS are integrated into a safety system referred to as the Plant Protection System (PPS). PPS performs the following functions:

- Acquires and analyzes sensor and contact inputs
- Performs computations and logic operations on acquired variables
- Performs coincidence logic voting
- Initiates automatic actuations for
  - Reactor Scram
  - ECCS
  - Emergency Diesel Generators (EDGs)
  - RCIC
  - NSSSS
- Provides manual component and system level actuations for the following:
  - Reactor Scram
  - ECCS
  - RCIC
  - NSSSS
- Provides manual trip and bypass capabilities
- Generates indication and alarm signals, which are also exported to external systems
- Provides required interlocks for high to low pressure system interface components

As defined in IEEE Std 603, PPS architecture consists of four Channels for input and processing, and four Divisions of voting logic and component actuation. The four channels are designated A – D, and four divisions are designated 1 -- 4, aligning to the instrument, mechanical, and electrical separation of the plant.

A system level actuation is a manual or automatic control function executed by all applicable divisions simultaneously when the monitored parameters reach their allowable value and coincidence logic is made up indicating validity of the parameters monitored. For system level safety actuations, PPS logic architecture is divided into three levels. Level 1 architecture is composed of the four channels, while Levels 2 and 3 together make up the division. Figure XX shows a summary functional diagram of the described architecture. Each Level is described below.

Figure XX Summary PPS Functional Diagram

Level 1 Bistable Processing Logic

Level 1 is the Bistable Processing Logic (BPL). The purposes of this level are acquisition of the majority of the safety related analog and contact inputs and performing computational and logical operations on those inputs. The results of these operations are input to soft signal comparators, which compare each value to an allowable value. Once an allowable value is exceeded, a bistable output is created. Bistable outputs from each channel provided to all four divisions Level 2 logic via unidirectional High Speed Links (HSLs) at which point the defined channel level ends.

The remaining sensor channels not directly received by the BPL have a similar process of input, logic operations, and output and are still channels for the purposes of resolution of potential Technical Specification limiting conditions. These exceptions are detailed within the associated channel function section.

A sensor channel extends from the sensor to the output of its bistable comparator, and includes signal acquisition and conditioning, computational and logical operation modules, and associated output data links to the PPS divisions. All sensor channels are the purview of Specification 3.3.1.

Level 2 Local Coincidence Logic

Level 2 is the Local Coincidence Logic (LCL). The main purpose of this logic level is to receive channel bistable outputs from all 4 channels, apply any existing manual trip or bypass commands, and to perform coincidence operations, resulting in a partial (divisional) trip signal. Coincidence operations are segregated, with dedicated processors and memory for reactor scram functions, and dedicated processors and memory for ECCS/NSSSS functions. To the extent possible, system level safety actuations for RPS and ECCS are arranged in a 2 out of 4 logic, and equipment protection and NSSSS actuations are 1 out of 1, 1 out of 2, 2 out of 2, or 2 out of 4 based on the reliability requirements of the supported mechanical systems. For RPS, once sufficient votes for a scram occur, the output is sent to the RPS Scram Matrix and Termination Units directly, no further processing is performed. Conversely for NSSSS and ECCS, when sufficient votes for an actuation occur, the division that corresponds to the correct divisionally powered components sends an actuation commend to Level 3. (e.g Division 2 LCLs send HPCI actuation commands, while Division 2 and division 4 send HPCI isolation commands).

In addition, the LCL processes manual commands from other sources. Manual system level actuations for ECCS and NSSSS are provided that accomplish the same lineups as the automatic initiation. While manual commands are divisional and therefore unvoted, they do require use of a manual confirmation hardwired switch in each division in order to complete the actuation request.

The other purpose of Level 2 are to receive certain signals that are not processed by Level 1 logic to accommodate design aspects including plant cable routes and scram response times. These exceptions are described in the detailed channel information of Bases 3.3.1.

All LCL hardware, from the termination of channel input bistable communication paths to outputs to either ILP hardware or the RPS termination units, are within the domain of specification 3.3.2.

Level 3 Integrated Logic Processor

The main purpose of Level 3 logic is to perform component fanout actuation commands for ECCS and NSSSS system level actuations. The ILP in each division receive automatic system level NSSSS and ECCS actuation commands via HSLs from the LCL within its division. The ILP address the actuation command to the correct Component Interface Module (CIM) or DO modules via the Safety Remote Node Controller (SRNC).

The ILP receives manual component control commands from Safety Displays (SDs) in the MCR via a separate communication path referred to as the Advant Fieldbus 100 (AF100). Each PPS channel/division pair has its own AF-100 communications network. In the event of a command conflict, system level automatic and manual commands have priority over manual.

The ILP also receives component status feedbacks as well as CIM internal status and communicates them to the SDs and Maintenance and Test Panel (MTP) via the AF-100 bus.

LPCI Injection Valve Differential Pressure (Function 12) is the only tech spec channel landed at logic Level 3, to accommodates existing plant wiring.

All ILP component fanout logic, from downstream of the channel communications link (HSLs, hardwires, etc) through the SRNCs and downstream termination panels are the purview of specification 3.3.2

INTERFACE COMPONENTS

Component Interface Module

The CIM is component that arbitrates command prioritization between the Safety Related PPS, and nonsafety Distributed Control System and Diverse Protection System, and is used when component operation from more than one control system is required. There is generally one CIM per component (the exception being valves where plant design has a ganged wiring scheme) therefore CIMs functionality and Limiting Conditions are applied via the supported mechanical system Specifications.

For components that require higher voltage and/or current than the CIM is rated for, an interposing solid state High Amperage Relay Panel (HARP) is utilized to establish the connection of CIM to driven component.

Advant Fieldbus 100

The AF100 is a communications network dedicated to each channel-division pair, connecting them to associated ancillaries such as the Maintenance and Test Cabinet (MTC) and SDs. All PPS manual component commands, manual bypasses and trips inserted from the Maintenance and Test Panel (MTP) as well as the CIM component feedbacks and CIM status feedbacks, are communicated via the AF100. Each SD has a dedicated AF100 branch. Further, while the AF100 is not required for PPS to perform its automatic credited safety functions, a total failure may affect the ability to manually align system valves using the either or both SDs in a division, therefore any resulting potential Limiting Conditions should be evaluated via the mechanical system Specifications.

Maintenance and Test Cabinet (MTC)

The MTC contains the Maintenance and Test Panel (MTP) and Interface and Test Processor (ITP). Communications to and from these panels are via the AF100 bus network, as such their functionality does not impact the credited safety functions of the PPS. However, these components do support system functionality as described below.

MTP

There is one MTP per channel/division pair. The MTP runs the interchannel sensor comparisons program to detect failures that could be caused by transmitter failures, loop power supply failures, input signal conditioning, and analog to digital conversion failures. This is a system licensing basis function that performs automated checks equivalent to the CHANNEL CHECK performed manually for those instruments outside of PPS. Further, the MTP is used to insert manual trips and bypasses of any channels as required for testing or repairs, as well as supporting various system diagnostic and troubleshooting interfaces. Finally, the MTP possesses the capability to load AC160 application software to any PM646A processor module with correct permissions and safeguards met. However, in order to conform to the system licensing basis defined in DI&C-ISG-04 requirements, the act of connecting the programming cable results in PM646A inoperability, as it introduces the potential to alter safety software while the safety equipment is in operation.

ITP

There is one ITP per channel/division pair. The ITP provides a means of monitoring the operation of the PPS and verifying that the accuracy of variables and constants are within system requirements. In addition to a large number of administrative supervisory and reporting tasks that provide for status monitoring across divisions, the ITP monitors status of the Scram Termination Units (TU) interface and initiation logic, and provides an alert if a scram demand from the LCL does not result in the correct corresponding change in Scram TU output.

<u>3/4/3.1 Plant Protection System Instrumentation</u>

<u>Cabinet Configuration</u>

There is one Bistable Logic Cabinet (BLC) per channel. The BLC contains the Advant Controller 160 (AC160) process control system hardware with the following configurations:

- Two redundant Safety AC and Safety DC cabinet power supplies
- Two redundant and diverse internal DC power supplies
- Two redundant PM646A Processor Modules, each running the BPL application, that each perform many of the analysis, computational, logical operations, as well as bistable logic functions for RPS, ECCS, and NSSSS.
- Two redundant HSLs, one from each PM646A module, which communicate channel bistable, bypass, and trip data to all four divisions LCLs
- A third PM646A used to process RG 1.97 variables for display on Safety Displays
- One CI631 AF100 Communications Module.
- Five analog input (AI) modules for sensor channel data acquisition
- Two digital input (DI) modules for Reactor Mode Switch Position
- Four digital output (DO) modules that route scram signals with short response time requirements directly to Level 2 from the BLC, bypassing BPL application cycle time
    - APRM two out of four voter contacts
    - MSIV closed position switches
    - Turbine Stop valve position switches
    - TCV fast closure Oil Pressure – Low switches

Actions:

Specification 3.3.1 permits a separate entry for each channel function. This takes into consideration the design redundancies of PPS and the reliability of a channel architecture that is independent of divisional safety functions.

Actions a1, b1, and b2 are modified by footnote #, which directs inserting a manual channel bypass in lieu of a manual channel trip for functions described as permissives. In the case where a channel is utilized to create a permissive function, it is inappropriate to insert a manual trip, as from the viewpoint of actuating logic to do so indicates the conditions monitored for permissive actuations are satisfied which is not necessarily the case depending on plant parameters. Because there is no channel to division dependency in the PPS actuation design, it would also be inappropriate to declare a mechanical train of ECCS or NSSSS inoperable to induce an allowed out of service time for a failed permissive related sensor channel. Thus, a channel bypass action, combined with requiring all permissive channels to be OPERABLE in their respective OPCONS, defines a limiting condition that enables an increasingly restrictive allowed out of service time commensurate to degree of function degradation.

Actions a1 and a2 specify all table actions must be performed. This distinction is to avoid ambiguity; no latitude for partial table implementation is provided.

Channel Functions

1. **Intermediate Range Monitors**
   Number of Channels: 8
   Channels required for OPERABILITY: 6 total, any 3 from channels A,C,E,G and any 3 from channels B, D, F, H
   Devices:
   BPL A
   IRM A:
   C51-1K002A IRM PREAMP CHANNEL 'A'
   C51-1K601A IRM A DRAWER
   10-S402-16-53 IRM Detector A

   IRM E:
   C51-1K002E IRM PREAMP CHANNEL 'E'
   C51-1K601E IRM E DRAWER
   10-S402-32-29 IRM Detector E
   BPL B
   IRM B:
   C51-1K002B IRM PREAMP CHANNEL 'B'
   C51-1K601B IRM B DRAWER
   10-S402-48-53 IRM Detector B

   IRM F:
   C51-1K002F IRM PREAMP CHANNEL 'F'
   C51-1K601F IRM F DRAWER
   10-S402-24-29 IRM Detector F
   BPL C
   IRM C:
   C51-1K002C IRM PREAMP CHANNEL 'C'
   C51-1K601C IRM C DRAWER
   10-S402-24-37 IRM Detector C

   IRM G:
   C51-1K002G IRM PREAMP CHANNEL 'G'
   C51-1K601G IRM G DRAWER
   10-S402-48-13 IRM Detector G
   BPL D
   IRM D:
   C51-1K002D IRM PREAMP CHANNEL 'D'
   C51-1K601D IRM D DRAWER
   10-S402-32-37 IRM Detector D

   IRM H:
   C51-1K002H IRM PREAMP CHANNEL 'H'
   C51-1K601H IRM H DRAWER

10-S402-16-13 IRM Detector H

Channel Description:

An IRM channel is composed of IRM detector, preamplifier and drawer as well as the associated drawer trip relay input to the BPL. The BPL receives both channels trip relay contacts, performs a simple OR function on contact status, then provides that output to its own division LCL only. The channel ends at the LCL digital input.

Logic Description: One out of two taken twice.
Functions actuated: Reactor Scram

Amplifying Details:

The IRM system consists of 8 detectors, with two channels allocated to each division. A minimum of 6 channels are required for the IRM function to be OPERABLE. The two IRM channel trip relays are input at the BPL Digital Input modules, and are ORed together to complete the channel trip signal. IRM scram signals are not propagated to other divisions; either IRM contact actuating is sufficient to create a scram demand for the associated division. Thus any IRM scram demand will cause a half scram. This logical arrangement is required to maintain the unit online during a bus outage of 1A(B)-Y160 busses, which each provide power to 4 IRM channels.

Only one IRM channel may be bypassed in channels A,C,E,G. Similarly, only one IRM may be bypassed from channels B,D, F, H. This is consistent with credited accident analysis assumptions that the detector closest to analyzed control rod accidents is assumed out of service.

For initial fuel loads and during shutdown margin demonstration testing performed as a special test, the shorting link function is enabled. When this is performed, SRM Upscale Trip scrams are enabled. Further, the logic coincidence changes such that any single SRM, IRM, or APRM Voter trip creates a full scram demand.

1a. Intermediate Range Monitors Neutron Flux - High

The IRMs monitor neutron flux levels from the upper range of the source range monitor (SRM) to the lower range of the average power range monitors (APRMs).The IRM is a 5 decade 10 range instrument, with upscale trip active in each range. Thus, as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during intermediate range power increase is due to control rod withdrawal. The IRM provides diverse protection for the rod worth minimizer (RWM), which monitors and controls the movement of control rods at low power. The IRMs prevent excessive rate of change in neutronic power via range scaling. Conversely, the RWM prevents the withdrawal of an out of sequence control rod during startup that could result in an unacceptable neutron flux excursion.

In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

The allowable value is select to be high enough to allow effective up-ranging scale overlap and to ensure that proper level scramming can be achieved in response to flux transients.

1b. Inoperative

This trip signal provides assurance that a minimum number of IRMs are OPERABLE. Anytime an IRM mode switch is moved to any position other than "Operate," the detector voltage drops below a preset level, or when a module is not plugged in, an inoperative trip signal will be received by the PPS unless the IRM is bypassed.

The Inoperative function was not specifically credited in the accident analysis. Six channels of Intermediate Range Monitor - Inop are required to be OPERABLE to ensure that no single instrument failure will preclude a scram on a valid signal. Since this function is not assumed in the safety analysis, there is no Allowable Value. This function is required to be OPERABLE when function 1a is required.

Surveillances

An event based CHANNEL CHECK is performed at in accordance with Surveillance Requirement 4.3.1.2

CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATIONS are performed in accordance with Surveillance Requirement 4.3.1.3

IRM Inoperative CHANNEL FUNCTIONAL TEST is performed in accordance with Surveillance Requirement 4.3.1.4

2. Average Power Range Monitor

Number of Channels: 4
Channels required for OPERABILITY: any 3 APRMs , all 4 Voters
Devices:
LCL 1:
APRM-1-1AR51 APRM 1 CHASSIS AR51
LPRM-1-1AR52 LPRM CHASSIS AR52 FOR APRM 1
APRM-1-LM-1A51 APRM 1 2/4 LOGIC MODULE A51
Associated LPRM detectors
LCL 2:
APRM-2-1AR31 APRM 2 CHASSIS AR31
LPRM-2-1AR32 LPRM CHASSIS AR32 FOR APRM 2
APRM-2-LM-1A31 APRM 2 2/4 LOGIC MODULE A31
Associated LPRM detectors
LCL 3:
APRM-3-1AR41 APRM 3 CHASSIS AR41
LPRM-3-1AR42 LPRM CHASSIS AR42 FOR APRM 3
APRM-3-LM-1A41 APRM 3 2/4 LOGIC MODULE A41
Associated LPRM detectors
LCL 4:
APRM-4-1AR11 APRM 4 CHASSIS AR11
LPRM-4-1AR12 LPRM CHASSIS AR12 FOR APRM 4
APRM-4-LM-1A11 APRM 4 2/4 LOGIC MODULE A11
Associated LPRM detectors

Channel Description: The channel extends from the individual LPRM detectors through the LCL digital input module, redundant processor modules, digital output module and includes its connection to the Scram TU.
Logic Description: 2 out of 4 internal to APRM, 1 out of 2 taken twice at the Scram TU
Functions Actuated: Reactor Scram

Amplifying Details:

APRM trip functions are initiated from four APRM chassis via four 2 out of 4 voter chassis. A minimum of three APRM channels are required to be OPERABLE to ensure that no single channel failure will preclude a trip from this function on a valid signal. Consequently, all voters, which provide the interface to PPS, are required to be operable.

For initial fuel loads and during shutdown margin demonstration testing performed as a special test, the shorting link function is enabled. When this is performed, SRM Upscale Trip scrams are enabled. Further, the logic coincidence changes such that any single SRM, IRM, or APRM Voter trip creates a full scram demand.

The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. 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 (gain adjustments).

The APRM 2 out of 4 voting logic resides internal to the NUMACs. APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four
voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels. Therefore, when placing an APRM channel in trip for functions 2a, 2b, 2c, 2d, and 2f, the trip must be inserted at the APRM and not the voter.

Redundant voter trip contacts X and Y are wired directly into the LCL DI module where they are ORed together. This routing was chosen due to the responses time requirements for these functions. From the perspective of the PPS, the type of scram vote is irrelevant. Further, PPS does not vote upon APRM voter outputs,   Instead, each divisional LCL act to deenergize its Scram TU When the respective OPRM output signal is received. Because APRM scram demands act directly at the division level, a scram demand of any unbypassed channel will result in a half scram.

a. Neutron Flux – Upscale (setdown)
   For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) function provides adequate thermal margin between the allowable values and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

   Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally, the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. Setdown trip function remains active until the mode switch is placed in the Run position. For most operation at low power levels, the function will provide a secondary scram to the IRM high flux scram function.

   The allowable value is established to prevent fuel damage from gross operational transients that occur while operating in the startup power range.

b. Simulated Thermal Power – Upscale
This function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is electronically filtered with a 6 second time constant representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. The trip level is varied as a function of recirculation drive flow (i.e., at lower core flows, the trip is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed control rod pattern) but is clamped at an upper limit that is always lower than the Average Power Range Monitor Fixed Neutron Flux - High Function Allowable Value. The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function provides protection against transients where THERMAL POWER increases slowly (such as the loss of feedwater heating event) and protects the fuel cladding integrity by ensuring that the MCPR safety Limit is not exceeded. During these events, the THERMAL POWER increase does not significantly lag the neutron flux response and, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the Average Power Range Monitor Fixed Neutron Flux - High Function will provide a scram signal before the Average Power Range Monitor Flow Biased Simulated Thermal Power - High function.

Drive flow signal is developed from pitot tubes connected at a piping elbow in each loop which provide signals to 8 differential pressure detectors. An A loop drive flow and a B loop drive flow signal is provided to each APRM, which are in turn used in flow biasing STP trip level.

This function requires a valid calibrated drive flow signal and established correlation of drive flow to total core flow, which is performed in accordance with the SFCP.

A reduced Allowable Value is provided for the Simulated Thermal Power – Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Allowable Value equations for single loop operation are only valid for flows down to W = 7.6%. The Allowable Value does not go below 62.0% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 1).

c. Neutron Flux – Upscale
The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The Average Power Range Monitor Fixed Neutron Flux - High Function is capable of generating a trip signal to prevent fuel damage or excessive RCS pressure. For the overpressurization protection analysis of Reference 5, the Neutron Flux – Upscale Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (S/RVs), limits the peak reactor pressure vessel (RPV) pressure to less than the

ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 6) takes credit for the Neutron Flux – Upscale Function to terminate the CRDA

The allowable value is established below the APRM analytical limit considering the instrument uncertainties to prevent fuel damage from gross operational transients

d. Inoperative
This trip signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime an APRM mode switch is moved to any position other than "Operate," an APRM module is unplugged, the electronic operating voltage is low, or the APRM has too few LPRM inputs (< 11), an inoperative trip signal will be output by the APRM, unless the APRM is bypassed. Since only one APRM may be bypassed, only one APRM may be inoperable without resulting in a trip signal. This Function was not specifically credited in the accident analysis, therefore there is no Allowable Value.

e. 2-Out-Of-4 Voter
The APRM 2 out of 4 voter internally votes APRM Functions independently of OPRM functions. Voter output is then is provided as a direct inputs to the PPS LCL via contacts X and Y. All voters must be OPERABLE to allow operational flexibility for APRM out of service times and still meet single failure criteria. Because this is a contact state change, no allowable value is assigned.

f. OPRM Upscale
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.

The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. As detailed in footnote c, OPRM trips are automatically enabled when APRM Simulated Thermal Power is > 29.5% and recirculation drive flow is <60% of rated core flow, when conditions are favorable to create thermal hydraulic instability. 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.

OPRM PDBA trip setpoints are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. All other tuning parameters and algorithm setpoints are nominal and controlled by station procedures. If an OPRM trip auto-enable setpoint is exceeded and the trip is not enabled, then the affected channel is inoperable until manually enabled.

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.

This function requires a valid calibrated drive flow signal and established correlation of drive flow to total core flow, which is performed in accordance with the SFCP

Table 3.3.1-1, Function 2.f, provide an Action 12 if OPRM Upscale trip capability is not maintained. For this condition, References 2 and 3 justified use of alternate methods to detect and suppress oscillations for a limited period of time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of the Action. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Surveillances

CHANNEL CHECKS are performed in accordance with Surveillance Requirement 4.3.1.5. An event based CHANNEL CHECK is performed at in accordance with Surveillance Requirement 4.3.1.2

CHANNEL FUNCTIONAL TESTS are performed in accordance with Surveillance Requirement 4.3.1.6,

This includes the drive flow function of the APRM chassis.

CHANNEL CALIBRATION is performed in accordance with Surveillance Requirement 4.3.1.7

A note has been provided to modify the Actions when Functional Unit 2.b and 2.c channels are inoperable due to failure of SR 4.3.1.1 and gain adjustments are necessary. The Note allows entry into associated Actions to be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power (i.e., the gain adjustment factor (GAF) is high (non-conservative)). The GAF for any channel is defined as the power value determined by the heat balance divided by the APRM reading for that channel. Upon completion of the gain adjustment, or expiration of the allowed time, the channel must be returned to OPERABLE status or the applicable Actions taken. This Note is based on the time required to perform gain adjustments on multiple channels.

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to the reactor power calculated from a heat balance if the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP.

CHANNEL CALIBRATION for the APRM Simulated Thermal Power – Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power – Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power – Upscale Function uses drive flow to vary the trip value. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to PPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow / core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within 10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power – Upscale Function and the OPRM Upscale Function.

LRPM inputs are calibrated every 2000 EFPH in accordance with Surveillance Requirement 4.3.1.8

3. Reactor Vessel Pressure

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A: PT-042-*N078A
BPL B: PT-042-*N078B
BPL C: PT-042-*N078C
BPL D: PT-042-*N078D
Channel Description: The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes its hardwired connections to the division level 2.
Logic Description: Two out of four
Functions Actuated:

a.	Reactor Vessel Steam Dome Pressure-High	Reactor Scram
b.	Reactor Vessel Pressure - High (RHRSDC Cut-In Permissive)	Group 2A isolation signal V
c.	1. LOCA initiation	ECCS actuation (partial) Group 8B isolation signal G (partial)
	2. Core Spray injection valve permissive	High to low pressure interlock
d.	HPCI Steam Supply Pressure – Low	Group 4B isolation signal LA
e.	RCIC Steam Supply Pressure – Low	Group 5B isolation signal KA

Amplifying Details:
Reactor Vessel Pressure signals are derived from four wide range transmitters arranged in a 2 out of 4 voting logic. For all functions except c2, a minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. For function c2, a minimum of four channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a permissive from this function.

These four wide range pressure detector signals are split at the detector output and shared via safety isolators with the RRCS function of the DCS. This sharing occurs external to the PPS to enable diversity of actuation. Reference Specification 3.3.4.1, Trip Function 2.

a. Reactor Vessel Steam Dome Pressure - High
An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure - High Function initiates a scram for transients that results in a pressure increase, counteracting the

pressure increase by rapidly reducing core power. For the overpressurization protection safety analysis, reactor scram along with the SRVs, limits the peak RPV pressure to less than the ASME Section III Code limits. For the reactor scram function, The Reactor Vessel Steam Dome Pressure - High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event. The Allowable Value is slightly higher than the operating pressure to permit normal operation without spurious trips. The Allowable Value provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This Allowable Value is effective at low power/flow conditions when the turbine stop valve and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

b. Reactor Vessel Pressure – High (RHRSDC Cut-In Permissive)
The Reactor Steam Dome Pressure - High Function is provided to isolate the shutdown cooling portion of the Residual Heat Removal (RHR) System. This isolation is provided for equipment protection to prevent potential system damage to low pressure piping.

c. LOCA initiation and Core Spray (permissive) bistable signals are derived redundantly and independently and the ability to manually trip or bypass either or both specific functions is provided.

1. LOCA initiation
Low reactor steam dome pressure coincident with high drywell pressure (function 8) are used to generate a LOCA signal. When sufficient channels pass their coincidence logic, all OPERABLE divisions initiate ECCS simultaneously.

The Allowable Value is low enough to prevent overpressuring the equipment in the low pressure ECCS, but high enough to ensure that the ECCS injection prevents the fuel peak cladding temperature from exceeding the limits of 10 CFR 50.46.

2. Core Spray (permissive)
Low reactor steam dome pressure signals are used as permissives for the Core Spray system. This ensures that, prior to opening the injection valves of the core spray system, the reactor pressure has fallen to a value below the systems maximum design pressure. The Reactor Steam Dome Pressure - Low is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in UFSAR. In addition, the Reactor Steam Dome Pressure - Low Function is assumed in the analysis of the recirculation line break. The core cooling function of the ECCS, along with the scram action of the PPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46

d. HPCI supply pressure low
This isolation is for equipment protection and indicates that pressure to the turbine may be too low to continue operation. This design feature protects the HPCI turbine and pump from damage when operating in a low pressure condition. Operation of the turbine at low steam pressure may result in the rotor stalling with continuous steam flow through

the turbine nozzle, or the pump stalling. There is no need to operate the HPCI System at low reactor pressure, since both the CS System and the RHR System in the Low Pressure Coolant Injection (LPCI) mode can be used for coolant injection.

The low steam line pressure HPCI turbine trip is a design feature and is not credited in the licensing basis analyses.

e. RCIC supply pressure low

This isolation is for equipment protection and indicates that pressure to the turbine may be too low to continue operation. This design feature protects the RCIC Turbine and Pump from damage when operating in a low pressure condition. Operation of the turbine at low steam pressure may result in the rotor stalling with continuous steam flow through the turbine nozzle, or the pump stalling. There is no need to operate the RCIC System at low reactor pressure, since both the CS System and the RHR System, in the Low Pressure Coolant Injection (LPCI) mode can be used for coolant injection.

The low steam line pressure RCIC turbine trip is a design feature and is not credited in the licensing basis analyses.

4. Reactor Vessel Water Level – Wide Range

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
PPS A: LT-042-*N081A
PPS B: LT-042-*N081B
PPS C: LT-042-*N081C
PPS D: LT-042-*N081D
Channel Description: The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the redundant hardwired outputs to the division level.
Logic Description: 2 out of 4
Functions Actuated:

a. Low, Low, Low Level 1
   ECCS Actuation
   Group 1A isolation signal C
   Group 7A isolation signal C
   Group 8A isolation signal C
   Group 8B isolation signal C
b. Low, Low Level 2
   HPCI Initiation
   RCIC Initiation
   Group 1B isolation signal B
   Group 3 isolation signal B
   Group 6A isolation signal B
   Group 6B isolation signal B
   Group 6C isolation signal B
   Group 7B isolation signal B
   Group 8B isolation signal B
   RE HVAC trip signal B
   RF HVAC trip signal B
c. High, Level 8
   HPCI turbine trip
   RCIC turbine shutdown

Amplifying Details:
Reactor Vessel Water Level - Low Low Low, Level 1 signals are initiated from four wide range level transmitters arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

These four detector signals are split at the detector output and shared via safety isolators with the RRCS function of the DCS. This sharing occurs external to the PPS to enable diversity of actuation. Reference Specification 3.3.4.1, Trip Function 1

a. Low, Low, Low Level 1
   ECCS actuation

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The low pressure ECCS and associated EDGs are initiated at Level 1 to ensure that core spray and RHR LPCI mode functions are available to prevent or minimize fuel damage.

To ensure RPV pressure is low enough for Core Spray and RHR LPCI injection, the Automatic Depressurization System actuates a High Drywell Pressure bypass timer upon receipt of a Low, Low, Low Level 1 signal and, without operator intervention, will cause a simultaneous actuation of Division 1 and 3 solenoids once all timers and permissives are met.

Isolation of the MSIVs and other interfaces with the reactor vessel actuates at Level 1 to prevent offsite does limits from being exceeded and to minimize reactor vessel inventory losses.

The Reactor Vessel Water Level - Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ECCS during the transients analyzed in the UFSAR. In addition, the Reactor Vessel Water Level - Low Low Low, Level 1 Function is directly assumed in the analysis of the recirculation line break described in Section 6.3.3 of the UFSAR. Level 1 actuated functions ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and prevent offsite dose from exceeding 10CFR100 limits.

The Reactor Vessel Water Level - Low Low Low, Level 1 Allowable Value is chosen to allow time for the low pressure core flooding systems to activate, and provide adequate cooling.

b. Low, Low Level 2
HPCI initiation
Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the HPCI System is initiated at Level 2 to maintain level above the top of the active fuel. The Reactor Vessel Water Level - Low
Low, Level 2 is one of the Functions assumed to be OPERABLE and capable of initiating HPCI during the transients analyzed in the UFSAR. The core cooling function of the ECCS, along with the scram action of the PPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

RCIC initiation

Low reactor pressure vessel (RPV) water level indicates that normal feedwater flow is insufficient to maintain reactor vessel water level and that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the RCIC System is initiated at Level 2 to assist in maintaining water level above the top of the active fuel. The RCIC function is not credited in the LOCA analysis.

Isolations

The allowable value for isolation signals is low enough to not actuate during normal scram RPV level response, but high enough such that RCIC and HPCI actuation can make up for minor inventory losses without actuation of low pressure ECCS.

If STGS is aligned to the unit Reactor Enclosure ventilation system, this actuation signal will provide a Group 6A and 6B PCIV isolation

c. High, Level 8
HPCI turbine trip
High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to trip the HPCI turbine to prevent overflow into the main steam lines (MSLs).

RCIC turbine shutdown
High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to close the RCIC steam supply valve.

5. Reactor Vessel Water Level – Narrow Range

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A: LT-042-*N080A
BPL B: LT-042-*N080B
BPL C: LT-042-*N080C
BPL D: LT-042-*N080D
Channel Description:
The sensor channel extends from the transmitter through the BPL analog input module, redundant processor modules, digital output module and includes its redundant HSL connections to the division level.
Logic Description: 2 out of 4
Functions Actuated:
Reactor Scram
ADS confirmatory Level signal
Group 2A isolation signal A
Group 2B isolation signal A

Amplifying Details:
Reactor Vessel Water Level - Low, Level 3 signals are initiated from four Narrow Range level transmitters arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

Reactor Scram Function
The Reactor Vessel Water Level - Low, Level 3 Allowable Value is selected to ensure that during normal operation the separator skirts are not uncovered, thus protecting available recirculation pump net positive suction head (NPSH) from significant carryunder. For transients involving loss of all normal feedwater flow, initiation of the low pressure ECCS subsystems at Reactor Vessel Water - Low Low Low, Level 1 will not be required. Further, the allowable value is far enough below the normal operating level to avoid spurious trips.

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at Level 3 to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level - Low, Level 3 Function is assumed in the analysis of the DBA LOCA as a secondary scram signal to high drywell pressure. The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the Emergency Core Cooling Systems (ECCS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

ADS confirmatory level function
Narrow range level is provided to the ADS logic as a diverse confirmatory level signal to prevent undesired spurious blowdown actuation in the presence of compound failures creating a spurious actuation signal.

Isolation function
Low RPV water level indicates that the capability to cool the fuel may be threatened. The isolation of the primary containment on Level 3 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded.

6. Scram Discharge Volume Water Level – High

Number of Channels: 4 transmitters, 4 switches
Channels required for OPERABILITY: Any 3 level transmitters, any 3 level switches
Devices:

BPL A:
- LT-047-*N012A
- LSH-047-*N013A

BPL B:
- LT-047-*N012B
- LSH-047-*N013B

BPL C:
- LT-047-*N012C
- LSH-047-*N013C

BPL D:
- LT-047-*N012D
- LSH-047-*N013D

Channel Description:

The sensor channel extends from the transmitter /switch through the BPL analog /digital input module, redundant processor modules, digital output module and includes its redundant HSL connections to the division level.

Logic Description: 2 out of 4
Functions Actuated:

a.	Level Transmitter	Reactor Scram
b.	Level Switch	Reactor Scram

Amplifying Details:

Scram Discharge Volume Water Level – High signals are initiated from two physically diverse and redundant sensor channel networks. There are four level transmitters arranged in a 2 out of 4 voting logic, and four level switches arranged in a 2 out of 4 voting logic. A minimum of three sensor channels of each type are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from either function upon receipt of a valid scram signal.

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods when they are tripped. With each drive requiring water displacement of between 2 and 3 gallons to complete a scram, the Allowable Value is determined by the free volume necessary to accommodate a full scram

7. Reactor Mode Switch Position

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices: S1
BPL A: contacts 2-2c
BPL B: contacts 18-18c
BPL C: contacts 34-34c
BPL D: contacts 50-50c
Channel Description:
The sensor channel extends from the switch contacts through the BPL digital input module, redundant processor modules, digital output module and includes its redundant HSL connections to the division level.
Logic Description: 2 out of 4
Functions Actuated: Reactor Scram

Amplifying Details:
The Reactor Mode Switch - Shutdown Position Function is initiated from four separate decks of the mode switch via specified contact combinations. These contact inputs are arranged in a 2 out of 4 voting logic and are routed via the PPS logic channels to provide manual reactor trip capability. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. This Function is not specifically credited in the accident analysis.

There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on reactor mode switch position.

8. Drywell Pressure – High

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A: PT-042-*N050A
BPL B: PT-042-*N050B
BPL C: PT-042-*N050C
BPL D: PT-042-*N050D
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated:
Reactor Scram
HPCI initiation
ECCS initiation (partial)
Group 2B Isolation signal H
Group 4B isolation signal H (Partial)
Group 5B isolation signal H (partial)
Group 6A isolation signal H
Group 6B isolation signal H
Group 6C isolation signal H
Group 7A isolation signal H
Group 7B isolation signal H
Group 8A isolation signal H
Group 8B isolation signal H
RE HVAC trip
RF HVAC trip

Amplifying Details:
High drywell pressure signals are initiated from four pressure transmitters arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. The Allowable Value was selected to be as low as possible and indicative of a LOCA inside primary containment without causing spurious trips.

Reactor Scram
A reactor scram is initiated to minimize the possibility of fuel damage and to reduce the amount of energy being added to the coolant and the primary containment. The Drywell Pressure - High Function scram is assumed to function for LOCA events inside the drywell.

HPCI initiation
The HPCI system provides coolant to the reactor vessel following a small break LOCA to meet 10CFR56.46 requirements until reactor vessel pressure decreases to the range where low pressure ECCS would be effective. It is designed to provide sufficient coolant to the reactor to prevent ADS actuation and maintain level above top of active fuel for all breaks of

one inch diameter or less. High drywell pressure indicates such a leak may have occurred and is directly used as a system initiation signal.

ECCS initiation
Low pressure ECCS and associated EDGs are initiated upon receipt of the Drywell Pressure - High Function coinciding with a Reactor Vessel Pressure – Low LOCA signal (function 3.c.1). Both signals are processed through their own 2 out of 4 voters and actuate all four divisions simultaneously.

Isolations
High drywell pressure can indicate a break in the RCPB inside the primary containment. The isolation of some of the primary containment isolation valves on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded.

If STGS is aligned to the unit Reactor Enclosure ventilation system, that isolation signal will provide a Group 6A and 6B PCIV isolation

9. Primary Containment Instrument Gas Line to Drywell Δ Pressure – Low

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
PDS-059-*06A
PDS-059-*06B
Channel Description: Individual detector input to valve auto close logic
Logic Description: Single channel
Functions Actuated: Group 7C Isolation Signal M

Amplifying Details:
This instrumentation is not routed through the PPS. Signal is created from local pressure switches that automatically isolates as Drywell pressure approaches PCIG header pressure and automatically resets once Drywell pressure subsides.

Motor operated valves are used in the PGIG to ADS gas supply lines. These are essential lines that provide a long-term backup to the ADS accumulators inside containment. These valves automatically isolate only when flow out of containment through these lines would be possible, which is the basis for the function allowable value. This isolation automatically resets when the initiating condition clears, however isolation valves will remain closed until manually reopened.

10. Condensate Storage Tank Level – Low

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A:
LT-049-*N035A
LT-049-*N035C
BPL B:
LT-055-*N061B
LT-055-*N061F
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated:
HPCI suction swap
RCIC suction swap

Amplifying Details:

Condensate Storage Tank Level - Low signals are initiated from four level switches arranged in a 2 out of 4 voting logic. Detector power is constrained to division 1 and division 2 which correspond to the actuation divisions for RCIC and HPCI respectively. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a swapover from this function on a valid signal.

The Allowable Value is high enough to ensure adequate pump suction head while water is being taken from the CST. The allowable value midpoint is equivalent to 2.3 feet indicated CST level, corrected for piping configurations. Low level in the CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valves between RCIC/HPCI and the CST are open and, upon receiving a RCIC/HPCI initiation signal, water for RCIC/HPCI injection would be taken from the CST. However, if the water level in the CST falls below the level setpoint for 12 seconds, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes.

11. Automatic Depressurization System (Permissives)

Number of Channels: 6

Channels required for OPERABILITY: 6

Devices:

BPL A

Core Spray Loop A

A CS pump	PT-052-*N055A
C CS pump	PT-052-*N055E
A RHR pump	PT-051-*N055A
C RHR pump	PT-051-*N055E

BPL C

Core Spray Loop B

B CS pump	PT-052-*N055C
D CS Pump	PT-052-*N055G
B RHR pump	PT-051-*N055C
D RHR pump	PT-051-*N055G

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description:

Core Spray Loop: 2 out of 2

RHR Loop: 1 out of 4

Function: 1 out of 6

Functions Actuated: ADS blowdown permissive

Amplifying Details:

ADS permissive signals are initiated from 8 pressure transmitters arranged in logic that mirrors running pump combinations analyzed to provide minimum adequate post blowdown inventory makeup capacity. Because this signal is a permissive action, all sensor channels are required to be OPERABLE.

ADS initiation results in the loss of reactor coolant inventory. Therefore ADS should not be automatically initiated unless the required RHR and/or CS pumps are available to provide cooling water to make up the loss of reactor water inventory. Makeup availability is indicated to ADS logic with either one loop of CS (i.e., both pumps in any loop) or any one RHR pump running.

No divisional dependency exists for this function, any one of the six CS loops or RHR pumps can satisfy the logic permissive for both Division 1 and Division 3 ADS logics to actuate. Upon the determination that a channel is no longer OPERABLE, the channel is bypassed per Action 10. For this function, placing the sensor channel in tripped is not appropriate because that would make up the logic to allow ADS to actuate without an assurance that the associated pump would automatically fulfill its safety function. The table action allowed out of service time is chosen to allow continued plant operation while repairs are performed, while establishing a per sensor channel time limit to return to service.

Further, the table action establishes the lowest functional limit of detectors, that if reached would indicate a critical degradation of function and necessitate a plant shutdown.

Pump discharge pressure signals are initiated from a single pressure transmitter on each pump. The pressure transmitters for the A AND C pump provide inputs for the A core spray loop. The pressure transmitters for the B AND D pump provide inputs for the B core spray loop. One pressure transmitter per RHR pump provides input to its associated channel. Functionally, any one channel is adequate for ADS safety related function to succeed. Therefore, in order to prevent the spurious operation of the ADS system due to failed ADS pump pressure switches, the required number of sensor channels for OPERABILTY is six and the minimum required channels prior to declaring the ADS system inoperable is two. A failed sensor channel requires operational bypass to be inserted and the channel to returned to OPERABLE within the allowed out of service time in order to ensure adequate redundancy is maintained with multiple channels out of service

12. LPCI Injection Valve Differential Pressure- Low (Permissive)

Number of Channels: 4
Channels required for OPERABILITY: 4
Devices:
ILP 1: PDT-051-*N058A
ILP 2: PDT-051-*N058B
ILP 3: PDT-051-*N058C
ILP 4: PDT-051-*N058D
Channel Description:
The sensor channel extends from the sensor through the ILP analog input module, and redundant processor modules
Logic Description: Single channel per LPCI train
Functions Actuated: RHR injection valve open permissive

Amplifying Details:
This permissive signal is initiated from four noncoincident pressure transmitters. Each acts upon its own train LPCI injection valve to enable automatic opening. Because this is both a permissive function and noncoincident, all channels must be OPERABLE.

This permissive is provided to prevent injection valve opening when reactor pressure may be greater than the low pressure piping design pressure and to protect against intersystem LOCA conditions.

13. Suppression Pool Water Level – High

Number of Channels: 2

Channels required for OPERABILITY: 2

Devices:

ILP 2: LT-055-*N062B

ILP 4: LT-055-*N062F

Channel Description:

The sensor channel extends from the sensor through the ILP analog input module, and redundant processor modules

Functions Actuated: HPCI suction swap to Suppression pool

Amplifying Details:

This signal is initiated from two level transmitters arranged in a 1 out of 2 logic that enters the PPS directly at level 2 logic. This function does not meet single failure criteria with any sensor channel out of service, therefore both sensor channels are required to be OPERABLE.

Excessively high suppression pool water could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through the safety/relief valves. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCI from the CST to the suppression pool to eliminate the possibility of HPCI continuing to provide additional water from a source outside containment. Safety analyses assume that the HPCI suction source is the suppression pool.

The Allowable Value is chosen to ensure that HPCI will be aligned for suction from the suppression pool before the water level reaches the point at which suppression pool design loads would be exceeded.

14. HPCI Steam Line Δ Pressure – High

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
BPL B: PDT-055-*N057B
BPL D: PDT-055-*N057D
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 2
Functions Actuated: Group 4A Isolation signal L

Amplifying Details:
This signal is initiated from two level transmitters arranged in a 1 out of 2 logic that enters the PPS directly at level 2 logic. This function does not meet single failure criteria with any sensor channel out of service, therefore both sensor channels are required to be OPERABLE

Signals are provided that initiate automatic isolation of abnormal leakage before the results of leakage become unacceptable. A high pressure drop, either in the forward or reverse flow directions, across either one of the two measurement devices provided in the HPCI steam supply line will result in an automatic isolation signal. The instrument allowable value range is calculated to be below the expected steam flow rate if the steam line were to break. Spurious system isolations are precluded by a 3 second time delay that prevents short-term flow peaks from initiating a system isolation. The leak detection sensors and associated electronics are designed to monitor the reactor coolant leakage over all expected ranges required for the safety of the plant. Both forward flow and reverse flow are capable of actuating an isolation command.

15. HPCI Turbine Exhaust Diaphragm Pressure – High

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
- BPL B:
  - PT-056-*N055B
  - PT-056-*N055F
- BPL D:
  - PT-056-*N055D
  - PT-056-*N055H

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4
Functions Actuated: Group 4A Isolation signal L

Amplifying Details:
This isolation signal is initiated from four pressure transmitters arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. The Allowable Value was selected to be high enough to prevent spurious trips but lower than the outer rupture diaphragm failure pressure.

This isolation is for equipment protection only and is used to indicate turbine pressure approaching casing pressure limits. The presence of a high turbine exhaust line pressure is an indication the turbine exhaust is restricted or closed. This can occur during turbine startup if a turbine exhaust valve is left in the closed position or if a check valve fails to open. The turbine is tripped on high turbine exhaust pressure to protect the exhaust line and turbine casing from overpressure.

16. HPCI Equipment Room Temperature – High

Number of Channels: 2

Channels required for OPERABILITY: 2

Devices:

BPL B: TE-055-*N030B

BPL D: TE-055-*N030D

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 1 out of 2

Functions Actuated: Group 4A Isolation signal L

Amplifying Details:

This signal is initiated from two temperature elements arranged in a 1 out of 2 voting logic. Both sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

17. HPCI Equipment Room ∆ Temperature – High

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
BPL B: TE-055-*N028B/29B
BPL D: TE-055-*N028D/29D
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated: Group 4A Isolation signal L

Amplifying Details:
This signal is initiated from two pairs of temperature elements arranged in a 1 out of 2 voting logic. Both sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. The Allowable Value was selected to be as low as possible and indicative of a smaller slower leak inside of the monitored location without causing spurious trips.

Room differential temperature alarms and isolations are provided to initiate automatic isolation (or permit manual isolation) of abnormal leakage before the results of a leak become unacceptable.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

18. HPCI Pipe Routing Area Temperature – High

Number of Channels: 8
Channels required for OPERABILITY: 8
Devices:
BPL B:
TE-055-*N025B
TE-055-*N025F
TE-055-*N025K
TE-055-*N025P
BPL D:
TE-055-*N025D
TE-055-*N025H
TE-055-*N025M
TE-055-*N025S
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 8
Functions Actuated: Group 4A Isolation signal L

Amplifying Details:
This signal is initiated from eight temperature elements arranged in a 1 out of 8 voting logic. All sensor channels are required to be OPERABLE. The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

19. Main Steam Line Isolation Valve – Closure

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
LCL 1: ZS-041-*22A and ZS-041*28A
LCL 2: ZS-041-*22C and ZS-041*28C
LCL 3: ZS-041-*22D and ZS-041*28D
LCL 4: ZS-041-*22B and ZS-041*28B
Channel Description:
The sensor channel extends from the switches through a BLC termination, hardwired to the associated LCL digital input module, redundant processor modules, digital output module and includes its hardwired connections to the Scram TU.
Logic Description: 2 out of 4
Functions Actuated: Reactor Scram

Amplifying Details:
MSIV closure signals are initiated from series connected position switches located on each inboard and outboard MSIV. For a given main steam line, either switch actuating results in a main steam line isolated signal. These signals are arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

MSIV closure results in loss of the main turbine and the condenser as a heat sink for the nuclear steam supply system and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a Main Steam Isolation Valve - Closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the ECCS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

20. Turbine Stop Valve – Closure

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

LCL 1: ZS-001-*04B	TSV 4
LCL 2: ZS-001-*04A	TSV 3
LCL 3: ZS-001-*04C	TSV 1
LCL 4: ZS-001-*04D	TSV 2

Channel Description:

The sensor channel extends from the switches through a BLC termination, hardwired to the associated LCL digital input module, redundant processor modules, digital output module and includes its hardwired connections to the Scram TU.

Logic Description: 2 out of 4

Functions Actuated: Reactor Scram

Amplifying Details:

Turbine Stop Valve – Closure signals are initiated from a position switch located on each of the four TSVs arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

This function is enabled whenever thermal power is >30% RTP as measured by main turbine first stage pressure detectors (a separately voted upon parameter in a 2 out of 4 logic). Below 30% power, the Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor Neutron Flux – High Functions are adequate to maintain necessary safety margins. Variability of the normal range of key reactor heat balance parameters including first stage pressure that are due to feedwater heater configuration and end of cycle power coastdown operations is a design input to the COLR and its referenced documentations.

This function supports Power Distribution Limits and EOC-RPT trip function . See specification 3.2.3 and 3.3.4.2.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. The EOC-RPT function trips both recirculation pumps, reducing coolant flow in order 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. TCV Fast Closure and TSV closure are 2 out of 4 voted inputs into the EOC-RPT function; a valid vote will trip both recirc pumps. Each EOC-RPT system may be manually bypassed at the MTP. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are indicated in the control room

21. Turbine Control Valve Fast Closure, Trip Oil Pressure – Low

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
LCL 1 PS-001-*102A CV 2
LCL 2 PS-001-*102C CV 1
LCL 3 PS-001-*102B CV 4
LCL 4 PS-001-*102D CV 3
Channel Description:
The sensor channel extends from the switches through a BLC termination, hardwired to the associated LCL digital input module, redundant processor modules, digital output module and includes its hardwired connections to the Scram TU.
Logic Description: 2 out of 4
Functions Actuated: Reactor Scram

Amplifying Details:
Turbine Control Valve Fast Closure, Trip Oil Pressure – Low signals are initiated from an oil pressure switches on EHC lines serving each of the four TSVs arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. The Allowable Value is selected high enough to detect imminent TCV fast closure.

This function is enabled whenever thermal power is >30% RTP as measured by main turbine first stage pressure detectors (a separately voted upon parameter in a 2 out of 4 logic). This Function is not required when THERMAL POWER is < 30% RTP, since the Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor Fixed Neutron Flux - High Functions are adequate to maintain the necessary safety margins. Variability of the normal range of key reactor heat balance parameters including first stage pressure that are due to feedwater heater configuration and end of cycle power coastdown operations is a design input to the COLR and is bounded by referenced documentations.

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Plant Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

This function supports Power Distribution Limits and EOC-RPT trip function . See specification 3.2.3 and 3.3.4.2

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. The EOC-RPT function trips both recirculation pumps, reducing coolant flow in order 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. TCV Fast Closure and TSV closure are 2 out of 4 voted inputs into the EOC-RPT function; a valid vote will trip both recirc pumps. Each EOC-RPT system may be manually bypassed at the MTP. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are indicated in the control room

22. Main Steam Line Pressure – Low

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A: PT-001-*N076A
BPL B: PT-001-*N076B
BPL C: PT-001-*N076C
BPL D: PT-001-*N076D

Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated: Group 1A Isolation signal P

Amplifying Details:
The MSL low pressure signal is initiated from four transmitters that are connected to the main steam lines, arranged in a 2 out of 4 configuration. Three sensor channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

Low MSL pressure indicates a potential problem with the DEHC pressure regulation, which can adversely affect reactor level and create excessive RPV cooldown rate. Closure of the MSIVs ensures that cooldown rate limit is not reached and minimizes RPV inventory losses if needed.

23. Main Steam Line Flow – High

Number of Channels: 4 per steam line

Channels required for OPERABILITY: 3 per steam line for a steam line with both MSIVs open

Devices:

	BPL A	BPL B	BPL C	BPL D
MSL A	PDT-041-*N086A	PDT-041-*N086B	PDT-041-*N086C	PDT-041-*N086D
MSL B	PDT-041-*N087A	PDT-041-*N087B	PDT-041-*N087C	PDT-041-*N087D
MSL C	PDT-041-*N088A	PDT-041-*N088B	PDT-041-*N088C	PDT-041-*N088D
MSL D	PDT-041-*N089A	PDT-041-*N089B	PDT-041-*N089C	PDT-041-*N089D

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4 voted on a per steam line basis

Functions Actuated: Group 1A Isolation signal E

Amplifying Details:

The MSL flow signals are initiated from 16 transmitters that are connected to the four MSLs. The four detectors assigned to any MSL are arranged in a 2 out of 4 voter configuration. The transmitters are arranged such that all four connected to one MSL would be able to detect the high flow. Three detectors of Main Steam Line Flow - High Function for each unisolated MSL are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL.

.

Main Steam Line Flow - High is provided to detect a break of any MSL and to initiate closure of all MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 100 limits.

24. Condenser Vacuum – Low

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A: PT-001-*N075A
BPL B: PT-001-*N075B
BPL C: PT-001-*N075C
BPL D: PT-001-*N075D

Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated: Group 1A isolation signal Q

Amplifying Details:
The Condenser Vacuum - Low Function is provided to prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum. The closure of the MSIVs is initiated to prevent the addition of steam that would lead to additional condenser pressurization and possible damage which would provide a potential radiation leakage path following an accident.

Condenser vacuum pressure signals are derived from four pressure transmitters that sense the pressure in the condenser, arranged in a 2 out of 4 voter configuration. Three sensor channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization.

25. Outboard MSIV Room Temperature - High

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

BPL A:	TE-041-*N010A
BPL B:	TE-041-*N010B
BPL C:	TE-041-*N010C
BPL D:	TE-041-*N010D

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4

Functions Actuated: Group 1A isolation F

Amplifying Details:

Outboard MSIV Room Temperature – High isolation signals are derived from four temperature transmitters that sense the room ambient temperature, arranged in a 2 out of 4 voter configuration. Three sensor channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. Room temperature isolations are provided as a redundant means to detect, alarm, and issue an isolation command for moderate system leaks at normal operating conditions.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to isolate high energy systems before the results of a leak become unacceptable. This function is not credited in the accident analysis

26. RWCS Δ Flow – High

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
BPL A:
FT-044-*N012A
FT-044-*N014A
FT-044-*N036A
BPL D:
FT-044-*N012D
FT-044-*N014D
FT-044-*N036D
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated: Group 3 isolation signal J

Amplifying Details:
This function is developed from three flow transmitters that are summed to provide a differential flow for the RWCU. The signal used for isolation is the sum of the three transmitters applied to a one out of 2 logic. Both sensor channels are required to be operable.

The high differential flow signal is provided to detect a break in the RWCU system, providing isolation to prevent exceeding offsite dose limits. A 45 second time delay is provided to prevent spurious trips during operational transients.

27. RWCS Area Temperature – High

Number of Channels: 12
Channels required for OPERABILITY: 12
Devices:
- BPL A
  - TE-044-*N016A
  - TE-044-*N016AA
  - TE-044-*N016E
  - TE-044-*N016J
  - TE-044-*N016N
  - TE-044-*N016T
- BPL D
  - TE-044-*N016D
  - TE-044-*N016DD
  - TE-044-*N016H
  - TE-044-*N016M
  - TE-044-*N016S
  - TE-044-*N016W

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4
Functions Actuated: Group 3 isolation signal J

Amplifying Details:
RWCS Area Temperature – High signals are derived from twelve transmitters arranged in a 1 out of 12 voting logic. All sensor channels are required to be OPERABLE.

RWCU area temperatures are provided as a redundant means to detect a leak from the RWCU system.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

28. RWCS Area Ventilation Δ Temperature – High

Number of Channels: 12

Channels required for OPERABILITY: 12

Devices:

BPL A

TE-044-*N022A/23A
TE-044-*N022AA/23AA
TE-044-*N022E/23E
TE-044-*N022J/23J
TE-044-*N022N/23N
TE-044-*N022T/23T

BPL D

TE-044-*N022D/23D
TE-044-*N022DD/23DD
TE-044-*N022H/23H
TE-044-*N022M/23M
TE-044-*N022S/23S
TE-044-*N022W/23W

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 1 out of 12

Functions Actuated: Group 3 Isolation signal J

Amplifying Details:

RWCS Area Ventilation Δ Temperature – High signals are derived from twelve pairs of transmitters arranged in a 1 out of 12 voting logic. All sensor channels are required to be OPERABLE.

RWCU area differential temperature is provided as a redundant means to detect small leaks from the RWCU system. If a small leak continued without isolation, offsite dose limits may be reached.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

29. SLCS Initiation

Number of Channels: 3
Channels required for OPERABILITY: 3
Devices:
BPL A: *A-P208 Running feedback signal
BPL B: *B-P208 Running feedback signal
BPL C: *C-P208 Running feedback signal
Channel Description:
The sensor channel extends from the sensor through the BPL digital input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 3
Functions Actuated: Group 3 Isolation signal Y

Amplifying Details:
Isolation of the RWCU system is required when SLC initiates to prevent dilution and removal of boron solution. Initiation signals originate from SLC pump start commands. Any SLC start command will isolate both RWCU valves.

30. RCIC Steam Line Δ Pressure – High

Number of Channels: 2

Channels required for OPERABILITY: 2

Devices:

BPL A: PDT-049-*N057A

BPL C: PDT-049-*N057C

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 1 out of 2

Functions Actuated: Group 5A isolation signal K

Amplifying Details:

RCIC Steam Line Δ Pressure – High signals are derived from two transmitters arranged in a 1 out of 2 voting logic. All sensor channels are required to be OPERABLE.

High steam line flow indicates a break in the RCIC steam supply line and automatically isolates the steam supply to the RCIC turbine. A 3 second time delay eliminates spurious isolations due to normal operating surges, such as on turbine startup.

The high steam line auto flow isolation is required to limit reactor coolant leakage outside Primary Containment. Room environments which result from HELB are calculated. The high steam line auto flow isolation design feature limits these calculated room environments.

31. RCIC Turbine Exhaust Diaphragm Pressure – High

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

BPL A:

PT-050-*N055A

PT-050-*N055E

BPL C:

PT-050-*N055C

PT-050-*N055G

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4

Functions Actuated: Group 5A isolation signal K

Amplifying Details:

RCIC Turbine Exhaust Diaphragm Pressure – High signals are derived from four transmitters arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

This isolation is for equipment protection and is used to indicate turbine pressure approaching casing pressure limits. The presence of a high turbine exhaust line pressure is an indication the turbine exhaust is restricted or closed. This can occur during turbine startup if a turbine exhaust valve is left in the closed position or if a check valve fails to open. The turbine is tripped on high turbine exhaust pressure to protect the exhaust line and turbine casing from overpressure. The trip setpoint is above the highest expected exhaust line operating pressure and below the setpoint of the rupture disc.

The high turbine exhaust pressure RCIC turbine trip design feature is not specifically credited in licensing basis analyses. It is also not required to support a function that is credited in licensing basis analyses.

32. RCIC Equipment Room Temperature – High

Number of Channels: 2

Channels required for OPERABILITY: 2

Devices:

BPL A: TE-049-*N023A

BPL C: TE-049-*N023C

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 1 out of 2

Functions Actuated: Group 5A isolation signal K

Amplifying Details:

RCIC Equipment Room Temperature – High signals are derived from two transmitters arranged in a 1 out of 2 voting logic. All sensor channels are required to be OPERABLE.

Equipment room temperatures are provided as a redundant means to detect, alarm, and issue an isolation command for moderate system leaks at normal operating conditions. This function is not credited in the accident analysis.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

33. RCIC Equipment Room Δ Temperature – High

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
BPL A: TE-049-*N021A/22A
BPL C: TE-049-*N021C/22C
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 2
Functions Actuated: Group 5A isolation signal K

Amplifying Details:
RCIC Equipment Room Δ Temperature – High signals are derived from two pairs of transmitters arranged in a 1 out of 2 voting logic. All sensor channels are required to be OPERABLE.

Equipment room differential temperature is provided as a redundant means to detect, alarm, and issue an isolation command for system leaks equivalent to approximately 5 gpm at normal operating conditions.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

34. RCIC Pipe Routing Area Temperature – High

Number of Channels: 10
Channels required for OPERABILITY: 10
Devices:
BPL A
TE-049-*N025A
TE-049-*N025E
TE-049-*N025J
TE-049-*N025N
TE-049-*N025T
BPL C
TE-049-*N025C
TE-049-*N025G
TE-049-*N025L
TE-049-*N025R
TE-049-*N025V
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 10
Functions Actuated: Group 5A isolation signal K

Amplifying Details:
RCIC Pipe Routing Area Temperature – High signals are derived from ten temperature transmitters arranged in a 1 out of 10 voting logic. All sensor channels are required to be OPERABLE.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

35. North Stack Effluent Radiation – High

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
BPL A: relay contact from RY-026-076
BPL C: relay contact from RY-026-076
Channel Description:
The sensor channel extends from the sensor through the BPL digital input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: Single Channel with relay contact output to BPL A and BPL C
Functions Actuated: Group 6A isolation signal W

Amplifying Details:
The safety related function is to monitor radioactivity in the North Stack Vent to prevent uncontrolled release of radioactive material to the environment. While the system is specifically designed for post-accident monitoring, the equipment operates continuously. Radioactivity levels are indicated and recorded, and abnormal conditions are annunciated in the MCR. If abnormal conditions are detected a signal is generated. This signal is not bypassed by closing slide gate dampers. Further this is a common unit component with outputs to both Unit 1 and Unit 2 Group 6A and Group 6B isolation logic.

36. Reactor Enclosure Ventilation Exhaust Duct Radiation – High

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

BPL A: RE-026-*N010A and RISH-026-*K609A
BPL B: RE-026-*N010B and RISH-026-*K609B
BPL C: RE-026-*N010C and RISH-026-*K609C
BPL D: RE-026-*N010D and RISH-026-*K609D

Channel Description:

The sensor channel extends from the sensor through the BPL digital input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4

Functions Actuated:

Group 6A isolation signal S
Group 6B isolation signal S
Group 6C isolation signal S
Group 7A isolation signal S
Group 7B isolation signal S
Group 8B isolation signal S
Reactor Enclosure HVAC isolation

Amplifying Details:

Reactor Enclosure Ventilation Exhaust Duct Radiation – High signals are derived from contact outputs of four radiation detection trip circuits arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

The Allowable Value is set high enough to be above background radiation with margin to minimize spurious trips.

The PRMS performs the safety related function of monitoring the radiation in the Reactor Enclosure ventilation exhaust to detect the amount of radioactive material exhausted to the South Stack vent for release to the environment. If high radiation is detected the PRMS provides a safety related input to isolate secondary containment and initiate SGTS/RERS. Group 6A and 6B isolation signal bypassed if the SGD to the unit reactor enclosure HVAC is closed.

37. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation – High

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

BPL A: RE-026-1N011A and RISH-026-1K610 A
BPL B: RE-026-1N011B and RISH-026-1K610 B
BPL C: RE-026-1N011C and RISH-026-1K610 C
BPL D: RE-026-1N011D and RISH-026-1K610 D

Channel Description:

The sensor channel extends from the sensor through the BPL digital input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4

Functions Actuated:

Group 6A isolation signal T
Group 6B isolation signal T
Refuel Floor HVAC isolation

Amplifying Details:

Refueling Area Unit 1 Ventilation Exhaust Duct Radiation – High signals are derived from contact outputs of four radiation detection trip circuits arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

The Allowable Value is set high enough to be above background radiation with margin to minimize spurious trips.

The PRMS performs the safety related function of monitoring the radiation in the Refuel Area ventilation exhaust to detect the amount of radioactive material exhausted to the South Stack vent for release to the environment. If high radiation is detected the PRMS provides a safety related input to isolate secondary containment and initiate SGTS. If STGS is aligned to the unit Reactor Enclosure ventilation system, that isolation signal will provide a Group 6A and 6B PCIV isolation.

38. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation – High

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
- BPL A: RE-026-2N011A and RISH-026-2K610 A
- BPL B: RE-026-2N011B and RISH-026-2K610 B
- BPL C: RE-026-2N011C and RISH-026-2K610 C
- BPL D: RE-026-2N011D and RISH-026-2K610 D

Channel Description:
The sensor channel extends from the sensor through the BPL digital input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4
Functions Actuated :
- Group 6A isolation signal T
- Group 6B isolation signal T
- Refuel Floor HVAC isolation

Amplifying Details:

Refueling Area Unit 2 Ventilation Exhaust Duct Radiation – High signals are derived from contact outputs of four radiation detection trip circuits arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

The Allowable Value is set high enough to be above background radiation with margin to minimize spurious trips.

The PRMS performs the safety related function of monitoring the radiation in the Refuel Area ventilation exhaust to detect the amount of radioactive material exhausted to the South Stack vent for release to the environment. If high radiation is detected the PRMS provides a safety related input to isolate secondary containment and initiate SGTS. If STGS is aligned to the unit Reactor Enclosure ventilation system, that isolation signal will provide a Group 6A and 6B PCIV isolation.

REFERENCES

1. NEDC-31300, “Single-Loop Operation Analysis for Limerick Generating Station, Unit 1,” August 1986.
2. NEDO-31960-A, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.
3. NEDO-31960-A, Supplement 1, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.
4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.
5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), “Guidelines for Stability Option III ‘Enable Region’ (TAC M92882),” September 17, 1996.

~~LIMITING SAFETY SYSTEM SETTINGS~~

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 15% Neutron Flux - Upscale (Setdown) trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux - Upscale setpoint; i.e., for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Simulated Thermal Power - Upscale setpoint, a time constant of 6 ± 0.6 seconds is introduced into the flow-biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow-biased setpoint as shown in Table 2.2.1-1.

A reduced Trip Setpoint and Allowable Value is provided for the Simulated Thermal Power – Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Trip Setpoint and Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Trip Setpoint and Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Trip Setpoint and Allowable Value equations for single loop operation are only valid for flows down to W = 7.6%. The Trip Setpoint and Allowable Value do not go below 61.5% and 62.0% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 1).

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unnecessary shutdown.

The APRM channels also include an Oscillation Power Range Monitor (OPRM) Upscale Function. The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into “cells” for evaluation by the OPRM algorithms.

References 2, 3 and 4 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.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. (NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. Refer to TS Bases 3/4.3.1 for further discussion concerning the recirculation drive flow/core flow relationship.) This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. See Reference 5 for additional discussion of OPRM Upscale trip enable region limits. These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Upscale trip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region.

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 a 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 oscillatory changes in the neutron flux for one or more cells in that channel.

There are four "sets" of OPRM related setpoints or adjustment parameters: a) OPRM trip auto-enable setpoints for APRM Simulated Thermal Power (29.5%) and recirculation drive flow (60%); b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; c) period based detection algorithm tuning parameters; and d) growth rate algorithm (GRA) and amplitude based algorithm (ABA) setpoints.

The first set, the OPRM auto-enable region setpoints, are treated as nominal setpoints with no additional margins added as discussed in Reference 5. The settings, 29.5% APRM Simulated Thermal Power and 60% recirculation drive flow, are defined (limit values) in a note to Table 2.2.1-1. The second set, the OPRM PBDA trip setpoints, are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. There are no allowable values for these setpoints. The third set, the OPRM PBDA "tuning" parameters, are established or adjusted in accordance with and controlled by station procedures. The fourth set, the GRA and ABA setpoints, in accordance with References 2 and 3, are established as nominal values only, and controlled by station procedures.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine stop valve and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

~~INTENTIONALLY LEFT BLANK~~

~~LIMITING SAFETY SYSTEM SETTINGS~~

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint has been used in transient analyses dealing with coolant inventory decrease. The scram setting was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

6. DELETED

7 Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems or a loss of drywell cooling. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant and to the primary containment. The trip setting was selected as low as possible without causing spurious trips.

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of 25.45 gallons of water.

9. Turbine Stop Valve-Closure

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position is a redundant channel to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

REFERENCES:

1. NEDC-31300, "Single-Loop Operation Analysis for Limerick Generating Station, Unit 1," August 1986.

2. NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

3. NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995.

4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.

5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), "Guidelines for Stability Option III 'Enable Region' (TAC M92882)," September 17, 1996.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. 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. The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, “Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function.” The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

The APRM Functions include five Functions accomplished by the four APRM channels (Functions 2.a, 2.b, 2.c, 2.d, and 2.f) and one accomplished by the four 2-Out-Of-4 Voter channels (Function 2.e). Two of the five Functions accomplished by the APRM channels are based on neutron flux only (Functions 2.a and 2.c), one Function is based on neutron flux and recirculation drive flow (Function 2.b) and one is based on equipment status (Function 2.d). The fifth Function accomplished by the APRM channels is the Oscillation Power Range Monitor (OPRM) Upscale trip Function 2.f, which is based on detecting oscillatory characteristics in the neutron flux. The OPRM Upscale Function is also dependent on average neutron flux (Simulated Thermal Power) and recirculation drive flow, which are used to automatically enable the output trip.

The Two-Out-Of-Four Logic Module includes 2-Out-Of-4 Voter hardware and the APRM Interface hardware. The 2-Out-Of-4 Voter Function 2.e votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. This voting is accomplished by the 2-Out-Of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The analysis in Reference 2 took credit for this redundancy in the justification of the 12-hour allowed out-of-service time for

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 $\geq$ 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.

A Note has been provided to modify the Actions when Functional Unit 2.b and 2.c channels are inoperable due to failure of SR 4.3.1.1 and gain adjustments are necessary. The Note allows entry into associated Actions to be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power (i.e., the gain adjustment factor (GAF) is high (non-conservative)). The GAF for any channel is defined as the power value determined by the heat balance divided by the APRM reading for that channel. Upon completion of the gain adjustment, or

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

expiration of the allowed time, the channel must be returned to OPERABLE status or the applicable Actions taken. This Note is based on the time required to perform gain adjustments on multiple channels.

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.

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

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.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

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).

The requirements of Action c limit the time the RPS scram logic, for any Function, would not accommodate single failure in both tip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in NEDC-30851P-A for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function must have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing the actions required by Action c restores RPS to a reliability level equivalent to that evaluated in NEDC-30851P-A, which justified a 12 hour allowable out of service time as allowed by Action b. To satisfy the requirements of Action c, the trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what OPERATIONAL CONDITION the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour allowable out of service time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

As noted, Action c is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-Out-Of-4 voter and other non-APRM channels for which Action c applies. For an inoperable APRM channel, the requirements of Action b can only be satisfied by tripping the inoperable APRM channel. 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.

If it is not desired to place the channel (or trip system) in trip to satisfy the requirements of Action a, Action b or Action c (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Action d requires that the Action defined by Table 3.3.1-1 for the applicable Function be initiated immediately upon expiration of the allowable out of service time.

Table 3.3.1-1, Function 2.f, references Action 10, which defines the action required if OPRM Upscale trip capability is not maintained. Action 10b is required to address identified equipment failures. Action 10a is to address common mode vendor/industry identified issues that render all four OPRM channels inoperable at once. For this condition, References 2 and 3 justified use of alternate methods to

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

detect and suppress oscillations for a limited period of time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of Action 10a. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Action 10a is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to be accomplished within the completion times allowed for LCO 3.3.1 Action a or Action b, as applicable. Action 10b applies when routine equipment OPERABILITY cannot be restored within the allowed completion times of LCO 3.3.1 Actions a or b, or if a common mode OPRM deficiency cannot be corrected and OPERABILITY of the OPRM Upscale Function restored within the 120-day allowed completion time of Action 10a.

The OPRM Upscale trip output shall be automatically enabled (not-bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. As noted in Table 4.3.1.1-1, Note c, CHANNEL CALIBRATION for the OPRM Upscale trip Function 2.f includes confirming that the auto-enable (not-bypassed) setpoints are correct. Other surveillances ensure that the APRM Simulated Thermal Power properly correlates with THERMAL POWER (Table 4.3.1.1-1, Note d) and that recirculation drive flow properly correlates with core flow (Table 4.3.1.1-1, Note g).

If any OPRM Upscale trip auto-enable setpoint is exceeded and the OPRM Upscale trip is not enabled, i.e., the OPRM Upscale trip is bypassed when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60%, then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the OPRM Upscale trip auto-enable setpoint(s) may be adjusted to place the channel in the enabled condition (not-bypassed). If the OPRM Upscale trip is placed in the enabled condition, the surveillance requirement is met and the channel is considered OPERABLE.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 4.3.1.1-1, Note g, CHANNEL CALIBRATION for the APRM Simulated Thermal Power - Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power - Upscale Function uses drive flow to vary the trip setpoint. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to RPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow / core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within 10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function.

For the Simulated Thermal Power - Upscale Function (Function 2.b), the CHANNEL CALIBRATION surveillance requirement is modified by two Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the Trip Setpoint. The as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the Trip Setpoint, then the channel shall be declared inoperable. The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (including readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to the reactor power calculated from a heat balance if the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP.

This Surveillance does not preclude making APRM channel adjustments, if desired, when the heat balance calculated reactor power is less than the APRM channel output. To provide close agreement between the APRM indicated power and to preserve operating margin, the APRM channels are normally adjusted to within +/- 2% of the heat balance calculated reactor power. However, this agreement is not required for OPERABILITY when APRM output indicates a higher reactor power than the heat balance calculated reactor power.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 3.3.1-2, Note "*", the redundant outputs from the 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8 to determine the interval between tests for application of Specification 4.3.1.3 (REACTOR PROTECTION SYSTEM RESPONSE TIME). The note further requires that testing of OPRM and APRM outputs shall be alternated.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that function, and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. This testing frequency is twice the frequency justified by References 2 and 3.

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for the APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions and the OPRM Upscale trip function (Table 3.3.1-2, Items 2.b, 2.c, and 2.f). Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Response time testing for the sensors as noted in Table 3.3.1-2 is not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Response time testing for sensors are not required based on the analysis in NEDO 32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.3.2 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

3/4.3.3 EMERGENCY CORE COOLING ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3.A REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a
3.3.3 variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close

INSTRUMENTATION

BASES

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3.3.3 3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

3.3.4.1 The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order 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.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression, and the response time of the system logic.

PTS Bases

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions 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. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

3.4.6

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

Unit 2

Revised Technical Specifications Bases (For Information Only)

~~2.2 LIMITING SAFETY SYSTEM SETTINGS~~

BASES

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each para-meter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. All four voters will trip (full scram) when any two unbypassed APRM channels exceed their trip setpoints.

APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) scram setting of 15% of RATED THERMAL POWER provides adequate hermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Tempera-ture coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

3/4.3.1 Plant Protection System Instrumentation Channels

This specification provides the limiting conditions for operation necessary to preserve the ability of the systems supported to perform its intended function even during periods when instrument channels may be out of service because of maintenance. For many functions, four channels are provided and only three channels are needed to satisfy the single failure design criteria and to perform the safety function. As a result, one channel may be removed from service to conduct required surveillances.

Instruments associated with reactor trip function meet the requirements of IEEE-279 for nuclear power plant protection systems. Instrument surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and instrument maintenance outage times have been aligned to the system out of service times for the functions they support.

PPS Overview

Collectively, the logic circuits for reactor scram, NSSSS, and ECCS are integrated into a safety system referred to as the Plant Protection System (PPS). PPS performs the following functions:

- Acquires and analyzes sensor and contact inputs
- Performs computations and logic operations on acquired variables
- Performs coincidence logic voting
- Initiates automatic actuations for
    - Reactor Scram
    - ECCS
    - Emergency Diesel Generators (EDGs)
    - RCIC
    - NSSSS
- Provides manual component and system level actuations for the following:
    - Reactor Scram
    - ECCS
    - RCIC
    - NSSSS
- Provides manual trip and bypass capabilities
- Generates indication and alarm signals, which are also exported to external systems
- Provides required interlocks for high to low pressure system interface components

As defined in IEEE Std 603, PPS architecture consists of four Channels for input and processing, and four Divisions of voting logic and component actuation. The four channels are designated A – D, and four divisions are designated 1 -- 4, aligning to the instrument, mechanical, and electrical separation of the plant.

A system level actuation is a manual or automatic control function executed by all applicable divisions simultaneously when the monitored parameters reach their allowable value and coincidence logic is made up indicating validity of the parameters monitored. For system level safety actuations, PPS logic architecture is divided into three levels. Level 1 architecture is composed of the four channels, while Levels 2 and 3 together make up the division. Figure XX shows a summary functional diagram of the described architecture. Each Level is described below.

Figure XX Summary PPS Functional Diagram

Level 1 Bistable Processing Logic

Level 1 is the Bistable Processing Logic (BPL). The purposes of this level are acquisition of the majority of the safety related analog and contact inputs and performing computational and logical operations on those inputs. The results of these operations are input to soft signal comparators, which compare each value to an allowable value. Once an allowable value is exceeded, a bistable output is created. Bistable outputs from each channel provided to all four divisions Level 2 logic via unidirectional High Speed Links (HSLs) at which point the defined channel level ends.

The remaining sensor channels not directly received by the BPL have a similar process of input, logic operations, and output and are still channels for the purposes of resolution of potential Technical Specification limiting conditions. These exceptions are detailed within the associated channel function section.

A sensor channel extends from the sensor to the output of its bistable comparator, and includes signal acquisition and conditioning, computational and logical operation modules, and associated output data links to the PPS divisions. All sensor channels are the purview of Specification 3.3.1.

Level 2 Local Coincidence Logic

Level 2 is the Local Coincidence Logic (LCL). The main purpose of this logic level is to receive channel bistable outputs from all 4 channels, apply any existing manual trip or bypass commands, and to perform coincidence operations, resulting in a partial (divisional) trip signal. Coincidence operations are segregated, with dedicated processors and memory for reactor scram functions, and dedicated processors and memory for ECCS/NSSSS functions. To the extent possible, system level safety actuations for RPS and ECCS are arranged in a 2 out of 4 logic, and equipment protection and NSSSS actuations are 1 out of 1, 1 out of 2, 2 out of 2, or 2 out of 4 based on the reliability requirements of the supported mechanical systems. For RPS, once sufficient votes for a scram occur, the output is sent to the RPS Scram Matrix and Termination Units directly, no further processing is performed. Conversely for NSSSS and ECCS, when sufficient votes for an actuation occur, the division that corresponds to the correct divisionally powered components sends an actuation commend to Level 3. (e.g Division 2 LCLs send HPCI actuation commands, while Division 2 and division 4 send HPCI isolation commands).

In addition, the LCL processes manual commands from other sources. Manual system level actuations for ECCS and NSSSS are provided that accomplish the same lineups as the automatic initiation. While manual commands are divisional and therefore unvoted, they do require use of a manual confirmation hardwired switch in each division in order to complete the actuation request.

The other purpose of Level 2 are to receive certain signals that are not processed by Level 1 logic to accommodate design aspects including plant cable routes and scram response times. These exceptions are described in the detailed channel information of Bases 3.3.1.

All LCL hardware, from the termination of channel input bistable communication paths to outputs to either ILP hardware or the RPS termination units, are within the domain of specification 3.3.2.

Level 3 Integrated Logic Processor

The main purpose of Level 3 logic is to perform component fanout actuation commands for ECCS and NSSSS system level actuations. The ILP in each division receive automatic system level NSSSS and ECCS actuation commands via HSLs from the LCL within its division. The ILP address the actuation command to the correct Component Interface Module (CIM) or DO modules via the Safety Remote Node Controller (SRNC).

The ILP receives manual component control commands from Safety Displays (SDs) in the MCR via a separate communication path referred to as the Advant Fieldbus 100 (AF100). Each PPS channel/division pair has its own AF-100 communications network. In the event of a command conflict, system level automatic and manual commands have priority over manual.

The ILP also receives component status feedbacks as well as CIM internal status and communicates them to the SDs and Maintenance and Test Panel (MTP) via the AF-100 bus.

LPCI Injection Valve Differential Pressure (Function 12) is the only tech spec channel landed at logic Level 3, to accommodates existing plant wiring.

All ILP component fanout logic, from downstream of the channel communications link (HSLs, hardwires, etc) through the SRNCs and downstream termination panels are the purview of specification 3.3.2

INTERFACE COMPONENTS

Component Interface Module

The CIM is component that arbitrates command prioritization between the Safety Related PPS, and nonsafety Distributed Control System and Diverse Protection System, and is used when component operation from more than one control system is required. There is generally one CIM per component (the exception being valves where plant design has a ganged wiring scheme) therefore CIMs functionality and Limiting Conditions are applied via the supported mechanical system Specifications.

For components that require higher voltage and/or current than the CIM is rated for, an interposing solid state High Amperage Relay Panel (HARP) is utilized to establish the connection of CIM to driven component.

Advant Fieldbus 100

The AF100 is a communications network dedicated to each channel-division pair, connecting them to associated ancillaries such as the Maintenance and Test Cabinet (MTC) and SDs. All PPS manual component commands, manual bypasses and trips inserted from the Maintenance and Test Panel (MTP) as well as the CIM component feedbacks and CIM status feedbacks, are communicated via the AF100. Each SD has a dedicated AF100 branch. Further, while the AF100 is not required for PPS to perform its automatic credited safety functions, a total failure may affect the ability to manually align system valves using the either or both SDs in a division, therefore any resulting potential Limiting Conditions should be evaluated via the mechanical system Specifications.

Maintenance and Test Cabinet (MTC)

The MTC contains the Maintenance and Test Panel (MTP) and Interface and Test Processor (ITP). Communications to and from these panels are via the AF100 bus network, as such their functionality does not impact the credited safety functions of the PPS. However, these components do support system functionality as described below.

MTP

There is one MTP per channel/division pair. The MTP runs the interchannel sensor comparisons program to detect failures that could be caused by transmitter failures, loop power supply failures, input signal conditioning, and analog to digital conversion failures. This is a system licensing basis function that performs automated checks equivalent to the CHANNEL CHECK performed manually for those instruments outside of PPS. Further, the MTP is used to insert manual trips and bypasses of any channels as required for testing or repairs, as well as supporting various system diagnostic and troubleshooting interfaces. Finally, the MTP possesses the capability to load AC160 application software to any PM646A processor module with correct permissions and safeguards met. However, in order to conform to the system licensing basis defined in DI&C-ISG-04 requirements, the act of connecting the programming cable results in PM646A inoperability, as it introduces the potential to alter safety software while the safety equipment is in operation.

ITP

There is one ITP per channel/division pair. The ITP provides a means of monitoring the operation of the PPS and verifying that the accuracy of variables and constants are within system requirements. In addition to a large number of administrative supervisory and reporting tasks that provide for status monitoring across divisions, the ITP monitors status of the Scram Termination Units (TU) interface and initiation logic, and provides an alert if a scram demand from the LCL does not result in the correct corresponding change in Scram TU output.

<u>3/4/3.1 Plant Protection System Instrumentation</u>

<u>Cabinet Configuration</u>

There is one Bistable Logic Cabinet (BLC) per channel. The BLC contains the Advant Controller 160 (AC160) process control system hardware with the following configurations:

- Two redundant Safety AC and Safety DC cabinet power supplies
- Two redundant and diverse internal DC power supplies
- Two redundant PM646A Processor Modules, each running the BPL application, that each perform many of the analysis, computational, logical operations, as well as bistable logic functions for RPS, ECCS, and NSSSS.
- Two redundant HSLs, one from each PM646A module, which communicate channel bistable, bypass, and trip data to all four divisions LCLs
- A third PM646A used to process RG 1.97 variables for display on Safety Displays
- One CI631 AF100 Communications Module.
- Five analog input (AI) modules for sensor channel data acquisition
- Two digital input (DI) modules for Reactor Mode Switch Position
- Four digital output (DO) modules that route scram signals with short response time requirements directly to Level 2 from the BLC, bypassing BPL application cycle time
    - APRM two out of four voter contacts
    - MSIV closed position switches
    - Turbine Stop valve position switches
    - TCV fast closure Oil Pressure – Low switches

<u>Actions:</u>
Specification 3.3.1 permits a separate entry for each channel function. This takes into consideration the design redundancies of PPS and the reliability of a channel architecture that is independent of divisional safety functions.

Actions a1, b1, and b2 are modified by footnote #, which directs inserting a manual channel bypass in lieu of a manual channel trip for functions described as permissives. In the case where a channel is utilized to create a permissive function, it is inappropriate to insert a manual trip, as from the viewpoint of actuating logic to do so indicates the conditions monitored for permissive actuations are satisfied which is not necessarily the case depending on plant parameters. Because there is no channel to division dependency in the PPS actuation design, it would also be inappropriate to declare a mechanical train of ECCS or NSSSS inoperable to induce an allowed out of service time for a failed permissive related sensor channel. Thus, a channel bypass action, combined with requiring all permissive channels to be OPERABLE in their respective OPCONS, defines a limiting condition that enables an increasingly restrictive allowed out of service time commensurate to degree of function degradation.

Actions a1 and a2 specify all table actions must be performed. This distinction is to avoid ambiguity; no latitude for partial table implementation is provided.

Channel Functions

1. **Intermediate Range Monitors**
   Number of Channels: 8
   Channels required for OPERABILITY: 6 total, any 3 from channels A,C,E,G and any 3 from channels B, D, F, H
   Devices:
   BPL A
   IRM A:
   C51-1K002A IRM PREAMP CHANNEL 'A'
   C51-1K601A IRM A DRAWER
   10-S402-16-53 IRM Detector A

   IRM E:
   C51-1K002E IRM PREAMP CHANNEL 'E'
   C51-1K601E IRM E DRAWER
   10-S402-32-29 IRM Detector E
   BPL B
   IRM B:
   C51-1K002B IRM PREAMP CHANNEL 'B'
   C51-1K601B IRM B DRAWER
   10-S402-48-53 IRM Detector B

   IRM F:
   C51-1K002F IRM PREAMP CHANNEL 'F'
   C51-1K601F IRM F DRAWER
   10-S402-24-29 IRM Detector F
   BPL C
   IRM C:
   C51-1K002C IRM PREAMP CHANNEL 'C'
   C51-1K601C IRM C DRAWER
   10-S402-24-37 IRM Detector C

   IRM G:
   C51-1K002G IRM PREAMP CHANNEL 'G'
   C51-1K601G IRM G DRAWER
   10-S402-48-13 IRM Detector G
   BPL D
   IRM D:
   C51-1K002D IRM PREAMP CHANNEL 'D'
   C51-1K601D IRM D DRAWER
   10-S402-32-37 IRM Detector D

   IRM H:
   C51-1K002H IRM PREAMP CHANNEL 'H'
   C51-1K601H IRM H DRAWER

10-S402-16-13 IRM Detector H

Channel Description:

An IRM channel is composed of IRM detector, preamplifier and drawer as well as the associated drawer trip relay input to the BPL. The BPL receives both channels trip relay contacts, performs a simple OR function on contact status, then provides that output to its own division LCL only. The channel ends at the LCL digital input.

Logic Description: One out of two taken twice.
Functions actuated: Reactor Scram

Amplifying Details:

The IRM system consists of 8 detectors, with two channels allocated to each division. A minimum of 6 channels are required for the IRM function to be OPERABLE. The two IRM channel trip relays are input at the BPL Digital Input modules, and are ORed together to complete the channel trip signal. IRM scram signals are not propagated to other divisions; either IRM contact actuating is sufficient to create a scram demand for the associated division. Thus any IRM scram demand will cause a half scram. This logical arrangement is required to maintain the unit online during a bus outage of 1A(B)-Y160 busses, which each provide power to 4 IRM channels.

Only one IRM channel may be bypassed in channels A,C,E,G. Similarly, only one IRM may be bypassed from channels B,D, F, H. This is consistent with credited accident analysis assumptions that the detector closest to analyzed control rod accidents is assumed out of service.

For initial fuel loads and during shutdown margin demonstration testing performed as a special test, the shorting link function is enabled. When this is performed, SRM Upscale Trip scrams are enabled. Further, the logic coincidence changes such that any single SRM, IRM, or APRM Voter trip creates a full scram demand.

1a. Intermediate Range Monitors Neutron Flux - High

The IRMs monitor neutron flux levels from the upper range of the source range monitor (SRM) to the lower range of the average power range monitors (APRMs).The IRM is a 5 decade 10 range instrument, with upscale trip active in each range. Thus, as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during intermediate range power increase is due to control rod withdrawal. The IRM provides diverse protection for the rod worth minimizer (RWM), which monitors and controls the movement of control rods at low power. The IRMs prevent excessive rate of change in neutronic power via range scaling. Conversely, the RWM prevents the withdrawal of an out of sequence control rod during startup that could result in an unacceptable neutron flux excursion.

In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

The allowable value is select to be high enough to allow effective up-ranging scale overlap and to ensure that proper level scramming can be achieved in response to flux transients.

1b. Inoperative

This trip signal provides assurance that a minimum number of IRMs are OPERABLE. Anytime an IRM mode switch is moved to any position other than "Operate," the detector voltage drops below a preset level, or when a module is not plugged in, an inoperative trip signal will be received by the PPS unless the IRM is bypassed.

The Inoperative function was not specifically credited in the accident analysis. Six channels of Intermediate Range Monitor - Inop are required to be OPERABLE to ensure that no single instrument failure will preclude a scram on a valid signal. Since this function is not assumed in the safety analysis, there is no Allowable Value. This function is required to be OPERABLE when function 1a is required.

Surveillances

An event based CHANNEL CHECK is performed at in accordance with Surveillance Requirement 4.3.1.2

CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATIONS are performed in accordance with Surveillance Requirement 4.3.1.3

IRM Inoperative CHANNEL FUNCTIONAL TEST is performed in accordance with Surveillance Requirement 4.3.1.4

2. Average Power Range Monitor

Number of Channels: 4
Channels required for OPERABILITY: any 3 APRMs , all 4 Voters
Devices:
LCL 1:

APRM-1-1AR51	APRM 1 CHASSIS AR51
LPRM-1-1AR52	LPRM CHASSIS AR52 FOR APRM 1
APRM-1-LM-1A51	APRM 1 2/4 LOGIC MODULE A51
Associated LPRM detectors	

LCL 2:

APRM-2-1AR31	APRM 2 CHASSIS AR31
LPRM-2-1AR32	LPRM CHASSIS AR32 FOR APRM 2
APRM-2-LM-1A31	APRM 2 2/4 LOGIC MODULE A31
Associated LPRM detectors	

LCL 3:

APRM-3-1AR41	APRM 3 CHASSIS AR41
LPRM-3-1AR42	LPRM CHASSIS AR42 FOR APRM 3
APRM-3-LM-1A41	APRM 3 2/4 LOGIC MODULE A41
Associated LPRM detectors	

LCL 4:

APRM-4-1AR11	APRM 4 CHASSIS AR11
LPRM-4-1AR12	LPRM CHASSIS AR12 FOR APRM 4
APRM-4-LM-1A11	APRM 4 2/4 LOGIC MODULE A11
Associated LPRM detectors	

Channel Description: The channel extends from the individual LPRM detectors through the LCL digital input module, redundant processor modules, digital output module and includes its connection to the Scram TU.
Logic Description: 2 out of 4 internal to APRM, 1 out of 2 taken twice at the Scram TU
Functions Actuated: Reactor Scram

Amplifying Details:

APRM trip functions are initiated from four APRM chassis via four 2 out of 4 voter chassis. A minimum of three APRM channels are required to be OPERABLE to ensure that no single channel failure will preclude a trip from this function on a valid signal. Consequently, all voters, which provide the interface to PPS, are required to be operable.

For initial fuel loads and during shutdown margin demonstration testing performed as a special test, the shorting link function is enabled. When this is performed, SRM Upscale Trip scrams are enabled. Further, the logic coincidence changes such that any single SRM, IRM, or APRM Voter trip creates a full scram demand.

The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. 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 (gain adjustments).

The APRM 2 out of 4 voting logic resides internal to the NUMACs. APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four
voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels. Therefore, when placing an APRM channel in trip for functions 2a, 2b, 2c, 2d, and 2f, the trip must be inserted at the APRM and not the voter.

Redundant voter trip contacts X and Y are wired directly into the LCL DI module where they are ORed together. This routing was chosen due to the responses time requirements for these functions. From the perspective of the PPS, the type of scram vote is irrelevant. Further, PPS does not vote upon APRM voter outputs, Instead, each divisional LCL act to deenergize its Scram TU When the respective OPRM output signal is received. Because APRM scram demands act directly at the division level, a scram demand of any unbypassed channel will result in a half scram.

a. Neutron Flux – Upscale (setdown)
   For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) function provides adequate thermal margin between the allowable values and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

   Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally, the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. Setdown trip function remains active until the mode switch is placed in the Run position. For most operation at low power levels, the function will provide a secondary scram to the IRM high flux scram function.

   The allowable value is established to prevent fuel damage from gross operational transients that occur while operating in the startup power range.

b. Simulated Thermal Power – Upscale
This function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is electronically filtered with a 6 second time constant representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. The trip level is varied as a function of recirculation drive flow (i.e., at lower core flows, the trip is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed control rod pattern) but is clamped at an upper limit that is always lower than the Average Power Range Monitor Fixed Neutron Flux - High Function Allowable Value. The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function provides protection against transients where THERMAL POWER increases slowly (such as the loss of feedwater heating event) and protects the fuel cladding integrity by ensuring that the MCPR safety Limit is not exceeded. During these events, the THERMAL POWER increase does not significantly lag the neutron flux response and, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the Average Power Range Monitor Fixed Neutron Flux - High Function will provide a scram signal before the Average Power Range Monitor Flow Biased Simulated Thermal Power - High function.

Drive flow signal is developed from pitot tubes connected at a piping elbow in each loop which provide signals to 8 differential pressure detectors. An A loop drive flow and a B loop drive flow signal is provided to each APRM, which are in turn used in flow biasing STP trip level.

This function requires a valid calibrated drive flow signal and established correlation of drive flow to total core flow, which is performed in accordance with the SFCP.

A reduced Allowable Value is provided for the Simulated Thermal Power – Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Allowable Value equations for single loop operation are only valid for flows down to W = 7.6%. The Allowable Value does not go below 62.0% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 1).

c. Neutron Flux – Upscale
The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The Average Power Range Monitor Fixed Neutron Flux - High Function is capable of generating a trip signal to prevent fuel damage or excessive RCS pressure. For the overpressurization protection analysis of Reference 5, the Neutron Flux – Upscale Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (S/RVs), limits the peak reactor pressure vessel (RPV) pressure to less than the

ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 6) takes credit for the Neutron Flux – Upscale Function to terminate the CRDA

The allowable value is established below the APRM analytical limit considering the instrument uncertainties to prevent fuel damage from gross operational transients

d. Inoperative
This trip signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime an APRM mode switch is moved to any position other than "Operate," an APRM module is unplugged, the electronic operating voltage is low, or the APRM has too few LPRM inputs (< 11), an inoperative trip signal will be output by the APRM, unless the APRM is bypassed. Since only one APRM may be bypassed, only one APRM may be inoperable without resulting in a trip signal. This Function was not specifically credited in the accident analysis, therefore there is no Allowable Value.

e. 2-Out-Of-4 Voter
The APRM 2 out of 4 voter internally votes APRM Functions independently of OPRM functions. Voter output is then is provided as a direct inputs to the PPS LCL via contacts X and Y. All voters must be OPERABLE to allow operational flexibility for APRM out of service times and still meet single failure criteria. Because this is a contact state change, no allowable value is assigned.

f. OPRM Upscale
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.

The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. As detailed in footnote c, OPRM trips are automatically enabled when APRM Simulated Thermal Power is > 29.5% and recirculation drive flow is <60% of rated core flow, when conditions are favorable to create thermal hydraulic instability. 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.

OPRM PDBA trip setpoints are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. All other tuning parameters and algorithm setpoints are nominal and controlled by station procedures. If an OPRM trip auto-enable setpoint is exceeded and the trip is not enabled, then the affected channel is inoperable until manually enabled.

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.

This function requires a valid calibrated drive flow signal and established correlation of drive flow to total core flow, which is performed in accordance with the SFCP

Table 3.3.1-1, Function 2.f, provide an Action 12 if OPRM Upscale trip capability is not maintained. For this condition, References 2 and 3 justified use of alternate methods to detect and suppress oscillations for a limited period of time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of the Action. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Surveillances

CHANNEL CHECKS are performed in accordance with Surveillance Requirement 4.3.1.5. An event based CHANNEL CHECK is performed at in accordance with Surveillance Requirement 4.3.1.2

CHANNEL FUNCTIONAL TESTS are performed in accordance with Surveillance Requirement 4.3.1.6,

This includes the drive flow function of the APRM chassis.

CHANNEL CALIBRATION is performed in accordance with Surveillance Requirement 4.3.1.7

A note has been provided to modify the Actions when Functional Unit 2.b and 2.c channels are inoperable due to failure of SR 4.3.1.1 and gain adjustments are necessary. The Note allows entry into associated Actions to be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power (i.e., the gain adjustment factor (GAF) is high (non-conservative)). The GAF for any channel is defined as the power value determined by the heat balance divided by the APRM reading for that channel. Upon completion of the gain adjustment, or expiration of the allowed time, the channel must be returned to OPERABLE status or the applicable Actions taken. This Note is based on the time required to perform gain adjustments on multiple channels.

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to the reactor power calculated from a heat balance if the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP.

CHANNEL CALIBRATION for the APRM Simulated Thermal Power – Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power – Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power – Upscale Function uses drive flow to vary the trip value. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to PPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow / core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within 10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power – Upscale Function and the OPRM Upscale Function.

LRPM inputs are calibrated every 2000 EFPH in accordance with Surveillance Requirement 4.3.1.8

3. Reactor Vessel Pressure

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A: PT-042-*N078A
BPL B: PT-042-*N078B
BPL C: PT-042-*N078C
BPL D: PT-042-*N078D
Channel Description: The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes its hardwired connections to the division level 2.
Logic Description: Two out of four
Functions Actuated:

a.	Reactor Vessel Steam Dome Pressure-High	Reactor Scram
b.	Reactor Vessel Pressure - High (RHRSDC Cut-In Permissive)	Group 2A isolation signal V
c.	1. LOCA initiation	ECCS actuation (partial) Group 8B isolation signal G (partial)
	2. Core Spray injection valve permissive	High to low pressure interlock
d.	HPCI Steam Supply Pressure – Low	Group 4B isolation signal LA
e.	RCIC Steam Supply Pressure – Low	Group 5B isolation signal KA

Amplifying Details:
Reactor Vessel Pressure signals are derived from four wide range transmitters arranged in a 2 out of 4 voting logic. For all functions except c2, a minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. For function c2, a minimum of four channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a permissive from this function.

These four wide range pressure detector signals are split at the detector output and shared via safety isolators with the RRCS function of the DCS. This sharing occurs external to the PPS to enable diversity of actuation. Reference Specification 3.3.4.1, Trip Function 2.

a. Reactor Vessel Steam Dome Pressure - High
An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure - High Function initiates a scram for transients that results in a pressure increase, counteracting the

pressure increase by rapidly reducing core power. For the overpressurization protection safety analysis, reactor scram along with the SRVs, limits the peak RPV pressure to less than the ASME Section III Code limits. For the reactor scram function, The Reactor Vessel Steam Dome Pressure - High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event. The Allowable Value is slightly higher than the operating pressure to permit normal operation without spurious trips. The Allowable Value provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This Allowable Value is effective at low power/flow conditions when the turbine stop valve and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

b. Reactor Vessel Pressure – High (RHRSDC Cut-In Permissive)
The Reactor Steam Dome Pressure - High Function is provided to isolate the shutdown cooling portion of the Residual Heat Removal (RHR) System. This isolation is provided for equipment protection to prevent potential system damage to low pressure piping.

c. LOCA initiation and Core Spray (permissive) bistable signals are derived redundantly and independently and the ability to manually trip or bypass either or both specific functions is provided.

1. LOCA initiation
Low reactor steam dome pressure coincident with high drywell pressure (function 8) are used to generate a LOCA signal. When sufficient channels pass their coincidence logic, all OPERABLE divisions initiate ECCS simultaneously.

The Allowable Value is low enough to prevent overpressuring the equipment in the low pressure ECCS, but high enough to ensure that the ECCS injection prevents the fuel peak cladding temperature from exceeding the limits of 10 CFR 50.46.

2. Core Spray (permissive)
Low reactor steam dome pressure signals are used as permissives for the Core Spray system. This ensures that, prior to opening the injection valves of the core spray system, the reactor pressure has fallen to a value below the systems maximum design pressure. The Reactor Steam Dome Pressure - Low is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in UFSAR. In addition, the Reactor Steam Dome Pressure - Low Function is assumed in the analysis of the recirculation line break. The core cooling function of the ECCS, along with the scram action of the PPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46

d. HPCI supply pressure low
This isolation is for equipment protection and indicates that pressure to the turbine may be too low to continue operation. This design feature protects the HPCI turbine and pump from damage when operating in a low pressure condition. Operation of the turbine at low steam pressure may result in the rotor stalling with continuous steam flow through

the turbine nozzle, or the pump stalling. There is no need to operate the HPCI System at low reactor pressure, since both the CS System and the RHR System in the Low Pressure Coolant Injection (LPCI) mode can be used for coolant injection.

The low steam line pressure HPCI turbine trip is a design feature and is not credited in the licensing basis analyses.

e. RCIC supply pressure low

This isolation is for equipment protection and indicates that pressure to the turbine may be too low to continue operation. This design feature protects the RCIC Turbine and Pump from damage when operating in a low pressure condition. Operation of the turbine at low steam pressure may result in the rotor stalling with continuous steam flow through the turbine nozzle, or the pump stalling. There is no need to operate the RCIC System at low reactor pressure, since both the CS System and the RHR System, in the Low Pressure Coolant Injection (LPCI) mode can be used for coolant injection.

The low steam line pressure RCIC turbine trip is a design feature and is not credited in the licensing basis analyses.

4. Reactor Vessel Water Level – Wide Range

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
- PPS A: LT-042-*N081A
- PPS B: LT-042-*N081B
- PPS C: LT-042-*N081C
- PPS D: LT-042-*N081D

Channel Description: The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the redundant hardwired outputs to the division level.
Logic Description: 2 out of 4
Functions Actuated:

a. Low, Low, Low Level 1
   - ECCS Actuation
   - Group 1A isolation signal C
   - Group 7A isolation signal C
   - Group 8A isolation signal C
   - Group 8B isolation signal C

b. Low, Low Level 2
   - HPCI Initiation
   - RCIC Initiation
   - Group 1B isolation signal B
   - Group 3 isolation signal B
   - Group 6A isolation signal B
   - Group 6B isolation signal B
   - Group 6C isolation signal B
   - Group 7B isolation signal B
   - Group 8B isolation signal B
   - RE HVAC trip signal B
   - RF HVAC trip signal B

c. High, Level 8
   - HPCI turbine trip
   - RCIC turbine shutdown

Amplifying Details:
Reactor Vessel Water Level - Low Low Low, Level 1 signals are initiated from four wide range level transmitters arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

These four detector signals are split at the detector output and shared via safety isolators with the RRCS function of the DCS. This sharing occurs external to the PPS to enable diversity of actuation. Reference Specification 3.3.4.1, Trip Function 1

a. Low, Low, Low Level 1
   ECCS actuation

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The low pressure ECCS and associated EDGs are initiated at Level 1 to ensure that core spray and RHR LPCI mode functions are available to prevent or minimize fuel damage.

To ensure RPV pressure is low enough for Core Spray and RHR LPCI injection, the Automatic Depressurization System actuates a High Drywell Pressure bypass timer upon receipt of a Low, Low, Low Level 1 signal and, without operator intervention, will cause a simultaneous actuation of Division 1 and 3 solenoids once all timers and permissives are met.

Isolation of the MSIVs and other interfaces with the reactor vessel actuates at Level 1 to prevent offsite does limits from being exceeded and to minimize reactor vessel inventory losses.

The Reactor Vessel Water Level - Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ECCS during the transients analyzed in the UFSAR. In addition, the Reactor Vessel Water Level - Low Low Low, Level 1 Function is directly assumed in the analysis of the recirculation line break described in Section 6.3.3 of the UFSAR. Level 1 actuated functions ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and prevent offsite dose from exceeding 10CFR100 limits.

The Reactor Vessel Water Level - Low Low Low, Level 1 Allowable Value is chosen to allow time for the low pressure core flooding systems to activate, and provide adequate cooling.

b. Low, Low Level 2
HPCI initiation
Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the HPCI System is initiated at Level 2 to maintain level above the top of the active fuel. The Reactor Vessel Water Level - Low
Low, Level 2 is one of the Functions assumed to be OPERABLE and capable of initiating HPCI during the transients analyzed in the UFSAR. The core cooling function of the ECCS, along with the scram action of the PPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

RCIC initiation

Low reactor pressure vessel (RPV) water level indicates that normal feedwater flow is insufficient to maintain reactor vessel water level and that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the RCIC System is initiated at Level 2 to assist in maintaining water level above the top of the active fuel. The RCIC function is not credited in the LOCA analysis.

Isolations

The allowable value for isolation signals is low enough to not actuate during normal scram RPV level response, but high enough such that RCIC and HPCI actuation can make up for minor inventory losses without actuation of low pressure ECCS.

If STGS is aligned to the unit Reactor Enclosure ventilation system, this actuation signal will provide a Group 6A and 6B PCIV isolation

c. High, Level 8
HPCI turbine trip
High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to trip the HPCI turbine to prevent overflow into the main steam lines (MSLs).

RCIC turbine shutdown
High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to close the RCIC steam supply valve.

5. Reactor Vessel Water Level – Narrow Range

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A: LT-042-*N080A
BPL B: LT-042-*N080B
BPL C: LT-042-*N080C
BPL D: LT-042-*N080D
Channel Description:
The sensor channel extends from the transmitter through the BPL analog input module, redundant processor modules, digital output module and includes its redundant HSL connections to the division level.
Logic Description: 2 out of 4
Functions Actuated:
Reactor Scram
ADS confirmatory Level signal
Group 2A isolation signal A
Group 2B isolation signal A

Amplifying Details:
Reactor Vessel Water Level - Low, Level 3 signals are initiated from four Narrow Range level transmitters arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

Reactor Scram Function
The Reactor Vessel Water Level - Low, Level 3 Allowable Value is selected to ensure that during normal operation the separator skirts are not uncovered, thus protecting available recirculation pump net positive suction head (NPSH) from significant carryunder. For transients involving loss of all normal feedwater flow, initiation of the low pressure ECCS subsystems at Reactor Vessel Water - Low Low Low, Level 1 will not be required. Further, the allowable value is far enough below the normal operating level to avoid spurious trips.

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at Level 3 to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level - Low, Level 3 Function is assumed in the analysis of the DBA LOCA as a secondary scram signal to high drywell pressure. The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the Emergency Core Cooling Systems (ECCS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

ADS confirmatory level function
Narrow range level is provided to the ADS logic as a diverse confirmatory level signal to prevent undesired spurious blowdown actuation in the presence of compound failures creating a spurious actuation signal.

Isolation function
Low RPV water level indicates that the capability to cool the fuel may be threatened. The isolation of the primary containment on Level 3 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded.

6. Scram Discharge Volume Water Level – High

Number of Channels: 4 transmitters, 4 switches

Channels required for OPERABILITY: Any 3 level transmitters, any 3 level switches

Devices:

BPL A:

LT-047-*N012A

LSH-047-*N013A

BPL B:

LT-047-*N012B

LSH-047-*N013B

BPL C:

LT-047-*N012C

LSH-047-*N013C

BPL D:

LT-047-*N012D

LSH-047-*N013D

Channel Description:

The sensor channel extends from the transmitter /switch through the BPL analog /digital input module, redundant processor modules, digital output module and includes its redundant HSL connections to the division level.

Logic Description: 2 out of 4

Functions Actuated:

a. Level Transmitter	Reactor Scram
b. Level Switch	Reactor Scram

Amplifying Details:

Scram Discharge Volume Water Level – High signals are initiated from two physically diverse and redundant sensor channel networks. There are four level transmitters arranged in a 2 out of 4 voting logic, and four level switches arranged in a 2 out of 4 voting logic. A minimum of three sensor channels of each type are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from either function upon receipt of a valid scram signal.

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods when they are tripped. With each drive requiring water displacement of between 2 and 3 gallons to complete a scram, the Allowable Value is determined by the free volume necessary to accommodate a full scram

7. Reactor Mode Switch Position

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices: S1
BPL A: contacts 2-2c
BPL B: contacts 18-18c
BPL C: contacts 34-34c
BPL D: contacts 50-50c
Channel Description:
The sensor channel extends from the switch contacts through the BPL digital input module, redundant processor modules, digital output module and includes its redundant HSL connections to the division level.
Logic Description: 2 out of 4
Functions Actuated: Reactor Scram

Amplifying Details:
The Reactor Mode Switch - Shutdown Position Function is initiated from four separate decks of the mode switch via specified contact combinations. These contact inputs are arranged in a 2 out of 4 voting logic and are routed via the PPS logic channels to provide manual reactor trip capability. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. This Function is not specifically credited in the accident analysis.

There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on reactor mode switch position.

8. **Drywell Pressure – High**
Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A: PT-042-*N050A
BPL B: PT-042-*N050B
BPL C: PT-042-*N050C
BPL D: PT-042-*N050D
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated:
Reactor Scram
HPCI initiation
ECCS initiation (partial)
Group 2B Isolation signal H
Group 4B isolation signal H (Partial)
Group 5B isolation signal H (partial)
Group 6A isolation signal H
Group 6B isolation signal H
Group 6C isolation signal H
Group 7A isolation signal H
Group 7B isolation signal H
Group 8A isolation signal H
Group 8B isolation signal H
RE HVAC trip
RF HVAC trip

Amplifying Details:
High drywell pressure signals are initiated from four pressure transmitters arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. The Allowable Value was selected to be as low as possible and indicative of a LOCA inside primary containment without causing spurious trips.

Reactor Scram
A reactor scram is initiated to minimize the possibility of fuel damage and to reduce the amount of energy being added to the coolant and the primary containment. The Drywell Pressure - High Function scram is assumed to function for LOCA events inside the drywell.

HPCI initiation
The HPCI system provides coolant to the reactor vessel following a small break LOCA to meet 10CFR56.46 requirements until reactor vessel pressure decreases to the range where low pressure ECCS would be effective. It is designed to provide sufficient coolant to the reactor to prevent ADS actuation and maintain level above top of active fuel for all breaks of

one inch diameter or less. High drywell pressure indicates such a leak may have occurred and is directly used as a system initiation signal.

ECCS initiation
Low pressure ECCS and associated EDGs are initiated upon receipt of the Drywell Pressure - High Function coinciding with a Reactor Vessel Pressure – Low LOCA signal (function 3.c.1). Both signals are processed through their own 2 out of 4 voters and actuate all four divisions simultaneously.

Isolations
High drywell pressure can indicate a break in the RCPB inside the primary containment. The isolation of some of the primary containment isolation valves on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded.

If STGS is aligned to the unit Reactor Enclosure ventilation system, that isolation signal will provide a Group 6A and 6B PCIV isolation

9. Primary Containment Instrument Gas Line to Drywell Δ Pressure – Low

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
PDS-059-*06A
PDS-059-*06B
Channel Description: Individual detector input to valve auto close logic
Logic Description: Single channel
Functions Actuated: Group 7C Isolation Signal M

Amplifying Details:
This instrumentation is not routed through the PPS. Signal is created from local pressure switches that automatically isolates as Drywell pressure approaches PCIG header pressure and automatically resets once Drywell pressure subsides.

Motor operated valves are used in the PGIG to ADS gas supply lines. These are essential lines that provide a long-term backup to the ADS accumulators inside containment. These valves automatically isolate only when flow out of containment through these lines would be possible, which is the basis for the function allowable value. This isolation automatically resets when the initiating condition clears, however isolation valves will remain closed until manually reopened.

10. Condensate Storage Tank Level – Low

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A:
LT-049-*N035A
LT-049-*N035C
BPL B:
LT-055-*N061B
LT-055-*N061F
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated:
HPCI suction swap
RCIC suction swap

Amplifying Details:

Condensate Storage Tank Level - Low signals are initiated from four level switches arranged in a 2 out of 4 voting logic. Detector power is constrained to division 1 and division 2 which correspond to the actuation divisions for RCIC and HPCI respectively. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a swapover from this function on a valid signal.

The Allowable Value is high enough to ensure adequate pump suction head while water is being taken from the CST. The allowable value midpoint is equivalent to 2.3 feet indicated CST level, corrected for piping configurations. Low level in the CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valves between RCIC/HPCI and the CST are open and, upon receiving a RCIC/HPCI initiation signal, water for RCIC/HPCI injection would be taken from the CST. However, if the water level in the CST falls below the level setpoint for 12 seconds, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes.

11. Automatic Depressurization System (Permissives)

Number of Channels: 6
Channels required for OPERABILITY: 6
Devices:
BPL A
Core Spray Loop A

A CS pump	PT-052-*N055A
C CS pump	PT-052-*N055E
A RHR pump	PT-051-*N055A
C RHR pump	PT-051-*N055E

BPL C
Core Spray Loop B

B CS pump	PT-052-*N055C
D CS Pump	PT-052-*N055G
B RHR pump	PT-051-*N055C
D RHR pump	PT-051-*N055G

Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description:
Core Spray Loop: 2 out of 2
RHR Loop: 1 out of 4
Function: 1 out of 6
Functions Actuated: ADS blowdown permissive

Amplifying Details:
ADS permissive signals are initiated from 8 pressure transmitters arranged in logic that mirrors running pump combinations analyzed to provide minimum adequate post blowdown inventory makeup capacity. Because this signal is a permissive action, all sensor channels are required to be OPERABLE.

ADS initiation results in the loss of reactor coolant inventory. Therefore ADS should not be automatically initiated unless the required RHR and/or CS pumps are available to provide cooling water to make up the loss of reactor water inventory. Makeup availability is indicated to ADS logic with either one loop of CS (i.e., both pumps in any loop) or any one RHR pump running.

No divisional dependency exists for this function, any one of the six CS loops or RHR pumps can satisfy the logic permissive for both Division 1 and Division 3 ADS logics to actuate. Upon the determination that a channel is no longer OPERABLE, the channel is bypassed per Action 10. For this function, placing the sensor channel in tripped is not appropriate because that would make up the logic to allow ADS to actuate without an assurance that the associated pump would automatically fulfill its safety function. The table action allowed out of service time is chosen to allow continued plant operation while repairs are performed, while establishing a per sensor channel time limit to return to service.

Further, the table action establishes the lowest functional limit of detectors, that if reached would indicate a critical degradation of function and necessitate a plant shutdown.

Pump discharge pressure signals are initiated from a single pressure transmitter on each pump. The pressure transmitters for the A AND C pump provide inputs for the A core spray loop. The pressure transmitters for the B AND D pump provide inputs for the B core spray loop. One pressure transmitter per RHR pump provides input to its associated channel. Functionally, any one channel is adequate for ADS safety related function to succeed. Therefore, in order to prevent the spurious operation of the ADS system due to failed ADS pump pressure switches, the required number of sensor channels for OPERABILTY is six and the minimum required channels prior to declaring the ADS system inoperable is two. A failed sensor channel requires operational bypass to be inserted and the channel to returned to OPERABLE within the allowed out of service time in order to ensure adequate redundancy is maintained with multiple channels out of service

12. LPCI Injection Valve Differential Pressure- Low (Permissive)

Number of Channels: 4
Channels required for OPERABILITY: 4
Devices:
ILP 1: PDT-051-*N058A
ILP 2: PDT-051-*N058B
ILP 3: PDT-051-*N058C
ILP 4: PDT-051-*N058D
Channel Description:
The sensor channel extends from the sensor through the ILP analog input module, and redundant processor modules
Logic Description: Single channel per LPCI train
Functions Actuated: RHR injection valve open permissive

Amplifying Details:
This permissive signal is initiated from four noncoincident pressure transmitters. Each acts upon its own train LPCI injection valve to enable automatic opening. Because this is both a permissive function and noncoincident, all channels must be OPERABLE.

This permissive is provided to prevent injection valve opening when reactor pressure may be greater than the low pressure piping design pressure and to protect against intersystem LOCA conditions.

13. Suppression Pool Water Level – High

Number of Channels: 2

Channels required for OPERABILITY: 2

Devices:

ILP 2: LT-055-*N062B

ILP 4: LT-055-*N062F

Channel Description:

The sensor channel extends from the sensor through the ILP analog input module, and redundant processor modules

Functions Actuated: HPCI suction swap to Suppression pool

Amplifying Details:

This signal is initiated from two level transmitters arranged in a 1 out of 2 logic that enters the PPS directly at level 2 logic. This function does not meet single failure criteria with any sensor channel out of service, therefore both sensor channels are required to be OPERABLE.

Excessively high suppression pool water could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through the safety/relief valves. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCI from the CST to the suppression pool to eliminate the possibility of HPCI continuing to provide additional water from a source outside containment. Safety analyses assume that the HPCI suction source is the suppression pool.

The Allowable Value is chosen to ensure that HPCI will be aligned for suction from the suppression pool before the water level reaches the point at which suppression pool design loads would be exceeded.

14. HPCI Steam Line Δ Pressure – High

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
BPL B: PDT-055-*N057B
BPL D: PDT-055-*N057D
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 2
Functions Actuated: Group 4A Isolation signal L

Amplifying Details:
This signal is initiated from two level transmitters arranged in a 1 out of 2 logic that enters the PPS directly at level 2 logic. This function does not meet single failure criteria with any sensor channel out of service, therefore both sensor channels are required to be OPERABLE

Signals are provided that initiate automatic isolation of abnormal leakage before the results of leakage become unacceptable. A high pressure drop, either in the forward or reverse flow directions, across either one of the two measurement devices provided in the HPCI steam supply line will result in an automatic isolation signal. The instrument allowable value range is calculated to be below the expected steam flow rate if the steam line were to break. Spurious system isolations are precluded by a 3 second time delay that prevents short-term flow peaks from initiating a system isolation. The leak detection sensors and associated electronics are designed to monitor the reactor coolant leakage over all expected ranges required for the safety of the plant. Both forward flow and reverse flow are capable of actuating an isolation command.

15. HPCI Turbine Exhaust Diaphragm Pressure – High

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL B:
PT-056-*N055B
PT-056-*N055F
BPL D:
PT-056-*N055D
PT-056-*N055H
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated: Group 4A Isolation signal L

Amplifying Details:
This isolation signal is initiated from four pressure transmitters arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. The Allowable Value was selected to be high enough to prevent spurious trips but lower than the outer rupture diaphragm failure pressure.

This isolation is for equipment protection only and is used to indicate turbine pressure approaching casing pressure limits. The presence of a high turbine exhaust line pressure is an indication the turbine exhaust is restricted or closed. This can occur during turbine startup if a turbine exhaust valve is left in the closed position or if a check valve fails to open. The turbine is tripped on high turbine exhaust pressure to protect the exhaust line and turbine casing from overpressure.

16. HPCI Equipment Room Temperature – High

Number of Channels: 2

Channels required for OPERABILITY: 2

Devices:

BPL B: TE-055-*N030B

BPL D: TE-055-*N030D

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 1 out of 2

Functions Actuated: Group 4A Isolation signal L

Amplifying Details:

This signal is initiated from two temperature elements arranged in a 1 out of 2 voting logic. Both sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

17. HPCI Equipment Room Δ Temperature – High

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
BPL B: TE-055-*N028B/29B
BPL D: TE-055-*N028D/29D
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated: Group 4A Isolation signal L

Amplifying Details:
This signal is initiated from two pairs of temperature elements arranged in a 1 out of 2 voting logic. Both sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. The Allowable Value was selected to be as low as possible and indicative of a smaller slower leak inside of the monitored location without causing spurious trips.

Room differential temperature alarms and isolations are provided to initiate automatic isolation (or permit manual isolation) of abnormal leakage before the results of a leak become unacceptable.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

18. HPCI Pipe Routing Area Temperature – High

Number of Channels: 8
Channels required for OPERABILITY: 8
Devices:
- BPL B:
  - TE-055-*N025B
  - TE-055-*N025F
  - TE-055-*N025K
  - TE-055-*N025P
- BPL D:
  - TE-055-*N025D
  - TE-055-*N025H
  - TE-055-*N025M
  - TE-055-*N025S

Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 1 out of 8
Functions Actuated: Group 4A Isolation signal L

Amplifying Details:
This signal is initiated from eight temperature elements arranged in a 1 out of 8 voting logic. All sensor channels are required to be OPERABLE. The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

19. Main Steam Line Isolation Valve – Closure

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
LCL 1: ZS-041-*22A and ZS-041*28A
LCL 2: ZS-041-*22C and ZS-041*28C
LCL 3: ZS-041-*22D and ZS-041*28D
LCL 4: ZS-041-*22B and ZS-041*28B
Channel Description:
The sensor channel extends from the switches through a BLC termination, hardwired to the associated LCL digital input module, redundant processor modules, digital output module and includes its hardwired connections to the Scram TU.
Logic Description: 2 out of 4
Functions Actuated: Reactor Scram

Amplifying Details:
MSIV closure signals are initiated from series connected position switches located on each inboard and outboard MSIV. For a given main steam line, either switch actuating results in a main steam line isolated signal. These signals are arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

MSIV closure results in loss of the main turbine and the condenser as a heat sink for the nuclear steam supply system and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a Main Steam Isolation Valve - Closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the ECCS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

20. Turbine Stop Valve – Closure

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:

LCL 1: ZS-001-*04B	TSV 4
LCL 2: ZS-001-*04A	TSV 3
LCL 3: ZS-001-*04C	TSV 1
LCL 4: ZS-001-*04D	TSV 2

Channel Description:

The sensor channel extends from the switches through a BLC termination, hardwired to the associated LCL digital input module, redundant processor modules, digital output module and includes its hardwired connections to the Scram TU.

Logic Description: 2 out of 4
Functions Actuated: Reactor Scram

Amplifying Details:
Turbine Stop Valve – Closure signals are initiated from a position switch located on each of the four TSVs arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

This function is enabled whenever thermal power is >30% RTP as measured by main turbine first stage pressure detectors (a separately voted upon parameter in a 2 out of 4 logic). Below 30% power, the Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor Neutron Flux – High Functions are adequate to maintain necessary safety margins. Variability of the normal range of key reactor heat balance parameters including first stage pressure that are due to feedwater heater configuration and end of cycle power coastdown operations is a design input to the COLR and its referenced documentations.

This function supports Power Distribution Limits and EOC-RPT trip function . See specification 3.2.3 and 3.3.4.2.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. The EOC-RPT function trips both recirculation pumps, reducing coolant flow in order 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. TCV Fast Closure and TSV closure are 2 out of 4 voted inputs into the EOC-RPT function; a valid vote will trip both recirc pumps. Each EOC-RPT system may be manually bypassed at the MTP. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are indicated in the control room

21. Turbine Control Valve Fast Closure, Trip Oil Pressure – Low

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

LCL 1 PS-001-*102A CV 2
LCL 2 PS-001-*102C CV 1
LCL 3 PS-001-*102B CV 4
LCL 4 PS-001-*102D CV 3

Channel Description:

The sensor channel extends from the switches through a BLC termination, hardwired to the associated LCL digital input module, redundant processor modules, digital output module and includes its hardwired connections to the Scram TU.

Logic Description: 2 out of 4

Functions Actuated: Reactor Scram

Amplifying Details:

Turbine Control Valve Fast Closure, Trip Oil Pressure – Low signals are initiated from an oil pressure switches on EHC lines serving each of the four TSVs arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal. The Allowable Value is selected high enough to detect imminent TCV fast closure.

This function is enabled whenever thermal power is >30% RTP as measured by main turbine first stage pressure detectors (a separately voted upon parameter in a 2 out of 4 logic). This Function is not required when THERMAL POWER is < 30% RTP, since the Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor Fixed Neutron Flux - High Functions are adequate to maintain the necessary safety margins. Variability of the normal range of key reactor heat balance parameters including first stage pressure that are due to feedwater heater configuration and end of cycle power coastdown operations is a design input to the COLR and is bounded by referenced documentations.

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Plant Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

This function supports Power Distribution Limits and EOC-RPT trip function . See specification 3.2.3 and 3.3.4.2

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. The EOC-RPT function trips both recirculation pumps, reducing coolant flow in order 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. TCV Fast Closure and TSV closure are 2 out of 4 voted inputs into the EOC-RPT function; a valid vote will trip both recirc pumps. Each EOC-RPT system may be manually bypassed at the MTP. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are indicated in the control room

22. Main Steam Line Pressure – Low

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

BPL A: PT-001-*N076A
BPL B: PT-001-*N076B
BPL C: PT-001-*N076C
BPL D: PT-001-*N076D

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4

Functions Actuated: Group 1A Isolation signal P

Amplifying Details:

The MSL low pressure signal is initiated from four transmitters that are connected to the main steam lines, arranged in a 2 out of 4 configuration. Three sensor channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

Low MSL pressure indicates a potential problem with the DEHC pressure regulation, which can adversely affect reactor level and create excessive RPV cooldown rate. Closure of the MSIVs ensures that cooldown rate limit is not reached and minimizes RPV inventory losses if needed.

23. Main Steam Line Flow – High

Number of Channels: 4 per steam line

Channels required for OPERABILITY: 3 per steam line for a steam line with both MSIVs open

Devices:

	BPL A	BPL B	BPL C	BPL D
MSL A	PDT-041-*N086A	PDT-041-*N086B	PDT-041-*N086C	PDT-041-*N086D
MSL B	PDT-041-*N087A	PDT-041-*N087B	PDT-041-*N087C	PDT-041-*N087D
MSL C	PDT-041-*N088A	PDT-041-*N088B	PDT-041-*N088C	PDT-041-*N088D
MSL D	PDT-041-*N089A	PDT-041-*N089B	PDT-041-*N089C	PDT-041-*N089D

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4 voted on a per steam line basis

Functions Actuated: Group 1A Isolation signal E

Amplifying Details:

The MSL flow signals are initiated from 16 transmitters that are connected to the four MSLs. The four detectors assigned to any MSL are arranged in a 2 out of 4 voter configuration. The transmitters are arranged such that all four connected to one MSL would be able to detect the high flow. Three detectors of Main Steam Line Flow - High Function for each unisolated MSL are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL.

.

Main Steam Line Flow - High is provided to detect a break of any MSL and to initiate closure of all MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 100 limits.

24. Condenser Vacuum – Low

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A: PT-001-*N075A
BPL B: PT-001-*N075B
BPL C: PT-001-*N075C
BPL D: PT-001-*N075D

Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated: Group 1A isolation signal Q

Amplifying Details:
The Condenser Vacuum - Low Function is provided to prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum. The closure of the MSIVs is initiated to prevent the addition of steam that would lead to additional condenser pressurization and possible damage which would provide a potential radiation leakage path following an accident.

Condenser vacuum pressure signals are derived from four pressure transmitters that sense the pressure in the condenser, arranged in a 2 out of 4 voter configuration. Three sensor channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization.

25. Outboard MSIV Room Temperature - High

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

BPL A:	TE-041-*N010A
BPL B:	TE-041-*N010B
BPL C:	TE-041-*N010C
BPL D:	TE-041-*N010D

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4

Functions Actuated: Group 1A isolation F

Amplifying Details:

Outboard MSIV Room Temperature – High isolation signals are derived from four temperature transmitters that sense the room ambient temperature, arranged in a 2 out of 4 voter configuration. Three sensor channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. Room temperature isolations are provided as a redundant means to detect, alarm, and issue an isolation command for moderate system leaks at normal operating conditions.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to isolate high energy systems before the results of a leak become unacceptable. This function is not credited in the accident analysis

26. RWCS ∆ Flow – High

Number of Channels: 2

Channels required for OPERABILITY: 2

Devices:

BPL A:

FT-044-*N012A
FT-044-*N014A
FT-044-*N036A

BPL D:

FT-044-*N012D
FT-044-*N014D
FT-044-*N036D

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4

Functions Actuated: Group 3 isolation signal J

Amplifying Details:

This function is developed from three flow transmitters that are summed to provide a differential flow for the RWCU. The signal used for isolation is the sum of the three transmitters applied to a one out of 2 logic. Both sensor channels are required to be operable.

The high differential flow signal is provided to detect a break in the RWCU system, providing isolation to prevent exceeding offsite dose limits. A 45 second time delay is provided to prevent spurious trips during operational transients.

27. RWCS Area Temperature – High

Number of Channels: 12
Channels required for OPERABILITY: 12
Devices:
- BPL A
  - TE-044-*N016A
  - TE-044-*N016AA
  - TE-044-*N016E
  - TE-044-*N016J
  - TE-044-*N016N
  - TE-044-*N016T
- BPL D
  - TE-044-*N016D
  - TE-044-*N016DD
  - TE-044-*N016H
  - TE-044-*N016M
  - TE-044-*N016S
  - TE-044-*N016W

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4
Functions Actuated: Group 3 isolation signal J

Amplifying Details:
RWCS Area Temperature – High signals are derived from twelve transmitters arranged in a 1 out of 12 voting logic. All sensor channels are required to be OPERABLE.

RWCU area temperatures are provided as a redundant means to detect a leak from the RWCU system.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

28. RWCS Area Ventilation ∆ Temperature – High

Number of Channels: 12
Channels required for OPERABILITY: 12
Devices:
BPL A
TE-044-*N022A/23A
TE-044-*N022AA/23AA
TE-044-*N022E/23E
TE-044-*N022J/23J
TE-044-*N022N/23N
TE-044-*N022T/23T
BPL D
TE-044-*N022D/23D
TE-044-*N022DD/23DD
TE-044-*N022H/23H
TE-044-*N022M/23M
TE-044-*N022S/23S
TE-044-*N022W/23W
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 12
Functions Actuated: Group 3 Isolation signal J

Amplifying Details:
RWCS Area Ventilation ∆ Temperature – High signals are derived from twelve pairs of transmitters arranged in a 1 out of 12 voting logic. All sensor channels are required to be OPERABLE.

RWCU area differential temperature is provided as a redundant means to detect small leaks from the RWCU system. If a small leak continued without isolation, offsite dose limits may be reached.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

29. SLCS Initiation

Number of Channels: 3
Channels required for OPERABILITY: 3
Devices:
BPL A: *A-P208 Running feedback signal
BPL B: *B-P208 Running feedback signal
BPL C: *C-P208 Running feedback signal
Channel Description:
The sensor channel extends from the sensor through the BPL digital input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 3
Functions Actuated: Group 3 Isolation signal Y

Amplifying Details:
Isolation of the RWCU system is required when SLC initiates to prevent dilution and removal of boron solution. Initiation signals originate from SLC pump start commands. Any SLC start command will isolate both RWCU valves.

30. RCIC Steam Line ∆ Pressure – High

Number of Channels: 2

Channels required for OPERABILITY: 2

Devices:

BPL A: PDT-049-*N057A

BPL C: PDT-049-*N057C

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 1 out of 2

Functions Actuated: Group 5A isolation signal K

Amplifying Details:

RCIC Steam Line ∆ Pressure – High signals are derived from two transmitters arranged in a 1 out of 2 voting logic. All sensor channels are required to be OPERABLE.

High steam line flow indicates a break in the RCIC steam supply line and automatically isolates the steam supply to the RCIC turbine. A 3 second time delay eliminates spurious isolations due to normal operating surges, such as on turbine startup.

The high steam line auto flow isolation is required to limit reactor coolant leakage outside Primary Containment. Room environments which result from HELB are calculated. The high steam line auto flow isolation design feature limits these calculated room environments.

31. RCIC Turbine Exhaust Diaphragm Pressure – High

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

BPL A:

PT-050-*N055A

PT-050-*N055E

BPL C:

PT-050-*N055C

PT-050-*N055G

Channel Description:

The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4

Functions Actuated: Group 5A isolation signal K

Amplifying Details:

RCIC Turbine Exhaust Diaphragm Pressure – High signals are derived from four transmitters arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

This isolation is for equipment protection and is used to indicate turbine pressure approaching casing pressure limits. The presence of a high turbine exhaust line pressure is an indication the turbine exhaust is restricted or closed. This can occur during turbine startup if a turbine exhaust valve is left in the closed position or if a check valve fails to open. The turbine is tripped on high turbine exhaust pressure to protect the exhaust line and turbine casing from overpressure. The trip setpoint is above the highest expected exhaust line operating pressure and below the setpoint of the rupture disc.

The high turbine exhaust pressure RCIC turbine trip design feature is not specifically credited in licensing basis analyses. It is also not required to support a function that is credited in licensing basis analyses.

32. RCIC Equipment Room Temperature – High

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
BPL A: TE-049-*N023A
BPL C: TE-049-*N023C
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 2
Functions Actuated: Group 5A isolation signal K

Amplifying Details:
RCIC Equipment Room Temperature – High signals are derived from two transmitters arranged in a 1 out of 2 voting logic. All sensor channels are required to be OPERABLE.

Equipment room temperatures are provided as a redundant means to detect, alarm, and issue an isolation command for moderate system leaks at normal operating conditions. This function is not credited in the accident analysis.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

33. RCIC Equipment Room Δ Temperature – High

Number of Channels: 2
Channels required for OPERABILITY: 2
Devices:
BPL A: TE-049-*N021A/22A
BPL C: TE-049-*N021C/22C
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 2
Functions Actuated: Group 5A isolation signal K

Amplifying Details:
RCIC Equipment Room Δ Temperature – High signals are derived from two pairs of transmitters arranged in a 1 out of 2 voting logic. All sensor channels are required to be OPERABLE.

Equipment room differential temperature is provided as a redundant means to detect, alarm, and issue an isolation command for system leaks equivalent to approximately 5 gpm at normal operating conditions.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

34. RCIC Pipe Routing Area Temperature – High

Number of Channels: 10
Channels required for OPERABILITY: 10
Devices:
BPL A
TE-049-*N025A
TE-049-*N025E
TE-049-*N025J
TE-049-*N025N
TE-049-*N025T
BPL C
TE-049-*N025C
TE-049-*N025G
TE-049-*N025L
TE-049-*N025R
TE-049-*N025V
Channel Description:
The sensor channel extends from the sensor through the BPL analog input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 1 out of 10
Functions Actuated: Group 5A isolation signal K

Amplifying Details:
RCIC Pipe Routing Area Temperature – High signals are derived from ten temperature transmitters arranged in a 1 out of 10 voting logic. All sensor channels are required to be OPERABLE.

The Allowable Value was selected to be as low as possible and indicative of a leak inside of the monitored location without causing spurious trips, and to allow manual or automatic isolation of high energy systems before the results of a leak become unacceptable. This function is a defense in depth feature, no credit is taken in the accident analysis for detection and isolation of leaks before line break .

35. North Stack Effluent Radiation – High

Number of Channels: 2

Channels required for OPERABILITY: 2

Devices:

BPL A: relay contact from RY-026-076

BPL C: relay contact from RY-026-076

Channel Description:

The sensor channel extends from the sensor through the BPL digital input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: Single Channel with relay contact output to BPL A and BPL C

Functions Actuated: Group 6A isolation signal W

Amplifying Details:

The safety related function is to monitor radioactivity in the North Stack Vent to prevent uncontrolled release of radioactive material to the environment. While the system is specifically designed for post-accident monitoring, the equipment operates continuously. Radioactivity levels are indicated and recorded, and abnormal conditions are annunciated in the MCR. If abnormal conditions are detected a signal is generated. This signal is not bypassed by closing slide gate dampers. Further this is a common unit component with outputs to both Unit 1 and Unit 2 Group 6A and Group 6B isolation logic.

36. Reactor Enclosure Ventilation Exhaust Duct Radiation – High

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

BPL A: RE-026-*N010A and RISH-026-*K609A
BPL B: RE-026-*N010B and RISH-026-*K609B
BPL C: RE-026-*N010C and RISH-026-*K609C
BPL D: RE-026-*N010D and RISH-026-*K609D

Channel Description:

The sensor channel extends from the sensor through the BPL digital input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4

Functions Actuated:

Group 6A isolation signal S
Group 6B isolation signal S
Group 6C isolation signal S
Group 7A isolation signal S
Group 7B isolation signal S
Group 8B isolation signal S
Reactor Enclosure HVAC isolation

Amplifying Details:

Reactor Enclosure Ventilation Exhaust Duct Radiation – High signals are derived from contact outputs of four radiation detection trip circuits arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

The Allowable Value is set high enough to be above background radiation with margin to minimize spurious trips.

The PRMS performs the safety related function of monitoring the radiation in the Reactor Enclosure ventilation exhaust to detect the amount of radioactive material exhausted to the South Stack vent for release to the environment. If high radiation is detected the PRMS provides a safety related input to isolate secondary containment and initiate SGTS/RERS. Group 6A and 6B isolation signal bypassed if the SGD to the unit reactor enclosure HVAC is closed.

37. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation – High

Number of Channels: 4

Channels required for OPERABILITY: 3

Devices:

BPL A: RE-026-1N011A and RISH-026-1K610 A
BPL B: RE-026-1N011B and RISH-026-1K610 B
BPL C: RE-026-1N011C and RISH-026-1K610 C
BPL D: RE-026-1N011D and RISH-026-1K610 D

Channel Description:

The sensor channel extends from the sensor through the BPL digital input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.

Logic Description: 2 out of 4

Functions Actuated:

Group 6A isolation signal T
Group 6B isolation signal T
Refuel Floor HVAC isolation

Amplifying Details:

Refueling Area Unit 1 Ventilation Exhaust Duct Radiation – High signals are derived from contact outputs of four radiation detection trip circuits arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

The Allowable Value is set high enough to be above background radiation with margin to minimize spurious trips.

The PRMS performs the safety related function of monitoring the radiation in the Refuel Area ventilation exhaust to detect the amount of radioactive material exhausted to the South Stack vent for release to the environment. If high radiation is detected the PRMS provides a safety related input to isolate secondary containment and initiate SGTS. If STGS is aligned to the unit Reactor Enclosure ventilation system, that isolation signal will provide a Group 6A and 6B PCIV isolation.

38. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation – High

Number of Channels: 4
Channels required for OPERABILITY: 3
Devices:
BPL A: RE-026-2N011A and RISH-026-2K610 A
BPL B: RE-026-2N011B and RISH-026-2K610 B
BPL C: RE-026-2N011C and RISH-026-2K610 C
BPL D: RE-026-2N011D and RISH-026-2K610 D
Channel Description:
The sensor channel extends from the sensor through the BPL digital input module, redundant processor modules, digital output module and includes the HSL connections to the LCL.
Logic Description: 2 out of 4
Functions Actuated :
Group 6A isolation signal T
Group 6B isolation signal T
Refuel Floor HVAC isolation

Amplifying Details:

Refueling Area Unit 2 Ventilation Exhaust Duct Radiation – High signals are derived from contact outputs of four radiation detection trip circuits arranged in a 2 out of 4 voting logic. A minimum of three sensor channels are required to be OPERABLE to ensure that no single sensor channel failure will preclude a trip from this function on a valid signal.

The Allowable Value is set high enough to be above background radiation with margin to minimize spurious trips.

The PRMS performs the safety related function of monitoring the radiation in the Refuel Area ventilation exhaust to detect the amount of radioactive material exhausted to the South Stack vent for release to the environment. If high radiation is detected the PRMS provides a safety related input to isolate secondary containment and initiate SGTS. If STGS is aligned to the unit Reactor Enclosure ventilation system, that isolation signal will provide a Group 6A and 6B PCIV isolation.

REFERENCES

1. NEDC-31300, “Single-Loop Operation Analysis for Limerick Generating Station, Unit 1,” August 1986.
2. NEDO-31960-A, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.
3. NEDO-31960-A, Supplement 1, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.
4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.
5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), “Guidelines for Stability Option III ‘Enable Region’ (TAC M92882),” September 17, 1996.

~~LIMITING SAFETY SYSTEM SETTINGS~~

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 15% Neutron Flux - Upscale (Setdown) trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux - Upscale setpoint; i.e., for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Simulated Thermal Power - Upscale setpoint, a time constant of 6 ± 0.6 seconds is introduced into the flow-biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow-biased setpoint as shown in Table 2.2.1-1.

A reduced Trip Setpoint and Allowable Value is provided for the Simulated Thermal Power - Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Trip Setpoint and Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Trip Setpoint and Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Trip Setpoint and Allowable Value equations for single loop operation are only valid for flows down to W = 7.6%. The Trip Setpoint and Allowable Value do not go below 61.5% and 62.0% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 1).

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unneces-sary shutdown.

The APRM channels also include an Oscillation Power Range Monitor (OPRM) Upscale Function. The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into “cells” for evaluation by the OPRM algorithms.

References 2, 3 and 4 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.

~~LIMITING SAFETY SYSTEM SETTINGS~~

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. (NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. Refer to TS Bases 3/4.3.1 for further discussion concerning the recirculation drive flow/core flow relationship.) This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. See Reference 5 for additional discussion of OPRM Upscale trip enable region limits. These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Upscale trip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region.

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 a 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 oscillatory changes in the neutron flux for one or more cells in that channel.

There are four "sets" of OPRM related setpoints or adjustment parameters: a) OPRM trip auto-enable setpoints for APRM Simulated Thermal Power (29.5%) and recirculation drive flow (60%); b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; c) period based detection algorithm tuning parameters; and d) growth rate algorithm (GRA) and amplitude based algorithm (ABA) setpoints.

The first set, the OPRM auto-enable region setpoints, are treated as nominal setpoints with no additional margins added as discussed in Reference 5. The settings, 29.5% APRM Simulated Thermal Power and 60% recirculation drive flow, are defined (limit values) in a note to Table 2.2.1-1. The second set, the OPRM PBDA trip setpoints, are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. There are no allowable values for these setpoints. The third set, the OPRM PBDA "tuning" parameters, are established or adjusted in accordance with and controlled by station procedures. The fourth set, the GRA and ABA setpoints, in accordance with References 2 and 3, are established as nominal values only, and controlled by station procedures.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine stop valve and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

~~INTENTIONALLY LEFT BLANK~~

~~LIMITING SAFETY SYSTEM SETTINGS~~

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint has been used in transient analyses dealing with coolant inventory decrease. The scram setting was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

6. DELETED

7. Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems or a loss of drywell cooling. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant and to the primary containment. The trip setting was selected as low as possible without causing spurious trips.

~~LIMITING SAFETY SYSTEM SETTING~~

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of 25.58 gallons of water.

9. Turbine Stop Valve-Closure

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position is a redundant channel to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

~~LIMITING SAFETY SYSTEM SETTING~~

BASES

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

REFERENCES:

1. NEDC-31300, “Single-Loop Operation Analysis for Limerick Generating Station, Unit 1,” August 1986.

2. NEDO-31960-A, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

3. NEDO-31960-A, Supplement 1, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.

5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), “Guidelines for Stability Option III ‘Enable Region’ (TAC M92882),” September 17, 1996.

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. 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. The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function." The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

The APRM Functions include five Functions accomplished by the four APRM channels (Functions 2.a, 2.b, 2.c, 2.d, and 2.f) and one accomplished by the four 2-Out-Of-4 Voter channels (Function 2.e). Two of the five Functions accomplished by the APRM channels are based on neutron flux only (Functions 2.a and 2.c), one Function is based on neutron flux and recirculation drive flow (Function 2.b) and one is based on equipment status (Function 2.d). The fifth Function accomplished by the APRM channels is the Oscillation Power Range Monitor (OPRM) Upscale trip Function 2.f, which is based on detecting oscillatory characteristics in the neutron flux. The OPRM Upscale Function is also dependent on average neutron flux (Simulated Thermal Power) and recirculation drive flow, which are used to automatically enable the output trip.

The Two-Out-Of-Four Logic Module includes 2-Out-Of-4 Voter hardware and the APRM Interface hardware. The 2-Out-Of-4 Voter Function 2.e votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. This voting is accomplished by the 2-Out-Of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The analysis in Reference 2 took credit for this redundancy in the justification of the 12-hour allowed out-of-service time for

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.

A Note has been provided to modify the Actions when Functional Unit 2.b and 2.c channels are inoperable due to failure of SR 4.3.1.1 and gain adjustments are necessary. The Note allows entry into associated Actions to be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power (i.e., the gain adjustment factor (GAF) is high (non-conservative)). The GAF for any channel is defined as the power value determined by the heat balance divided by the APRM reading for that channel. Upon completion of the gain adjustment, or

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

expiration of the allowed time, the channel must be returned to OPERABLE status or the applicable Actions taken. This Note is based on the time required to perform gain adjustments on multiple channels.

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.

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

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.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

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).

The requirements of Action c limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in NEDC-30851P-A for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function must have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing the actions required by Action c restores RPS to a reliability level equivalent to that evaluated in NEDC-30851P-A, which justified a 12 hour allowable out of service time as allowed by Action b. To satisfy the requirements of Action c, the trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what OPERATIONAL CONDITION the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour allowable out of service time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

As noted, Action c is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-Out-Of-4 voter and other non-APRM channels for which Action c applies. For an inoperable APRM channel, the requirements of Action b can only be satisfied by tripping the inoperable APRM channel. 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.

If it is not desired to place the channel (or trip system) in trip to satisfy the requirements of Action a, Action b or Action c (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Action d requires that the Action defined by Table 3.3.1-1 for the applicable Function be initiated immediately upon expiration of the allowable out of service time.

Table 3.3.1-1, Function 2.f, references Action 10, which defines the action required if OPRM Upscale trip capability is not maintained. Action 10b is required to address identified equipment failures. Action 10a is to address common mode vendor/industry identified issues that render all four OPRM channels inoperable at once. For this condition, References 2 and 3 justified use of alternate methods to detect and suppress oscillations for a limited period of

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of Action 10a. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Action 10a is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to be accomplished within the completion times allowed for LCO 3.3.1 Action a or Action b, as applicable. Action 10b applies when routine equipment OPERABILITY cannot be restored within the allowed completion times of LCO 3.3.1 Actions a or b, or if a common mode OPRM deficiency cannot be corrected and OPERABILITY of the OPRM Upscale Function restored within the 120-day allowed completion time of Action 10a.

The OPRM Upscale trip output shall be automatically enabled (not-bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. As noted in Table 4.3.1.1-1, Note c, CHANNEL CALIBRATION for the OPRM Upscale trip Function 2.f includes confirming that the auto-enable (not-bypassed) setpoints are correct. Other surveillances ensure that the APRM Simulated Thermal Power properly correlates with THERMAL POWER (Table 4.3.1.1-1, Note d) and that recirculation drive flow properly correlates with core flow (Table 4.3.1.1-1, Note g).

If any OPRM Upscale trip auto-enable setpoint is exceeded and the OPRM Upscale trip is not enabled, i.e., the OPRM Upscale trip is bypassed when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60%, then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the OPRM Upscale trip auto-enable setpoint(s) may be adjusted to place the channel in the enabled condition (not-bypassed). If the OPRM Upscale trip is placed in the enabled condition, the surveillance requirement is met and the channel is considered OPERABLE.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 4.3.1.1-1, Note g, CHANNEL CALIBRATION for the APRM Simulated Thermal Power - Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power - Upscale Function uses drive flow to vary the trip setpoint. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to RPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow / core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within 10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function.

For the Simulated Thermal Power - Upscale Function (Function 2.b), the CHANNEL CALIBRATION surveillance requirement is modified by two Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the Trip Setpoint. The as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the Trip Setpoint, then the channel shall be declared inoperable. The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (including readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to the reactor power calculated from a heat balance if the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP.

This Surveillance does not preclude making APRM channel adjustments, if desired, when the heat balance calculated reactor power is less than the APRM channel output. To provide close agreement between the APRM indicated power and to preserve operating margin, the APRM channels are normally adjusted to within +/- 2% of the heat balance calculated reactor power. However, this agreement is not required for OPERABILITY when APRM output indicates a higher reactor power than the heat balance calculated reactor power.

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 3.3.1-2, Note "*", the redundant outputs from the 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8 to determine the interval between tests for application of Specification 4.3.1.3 (REACTOR PROTECTION SYSTEM RESPONSE TIME). The note further requires that testing of OPRM and APRM outputs shall be alternated.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that function, and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. This testing frequency is twice the frequency justified by References 2 and 3.

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for the APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions and the OPRM Upscale trip function (Table 3.3.1-2, Items 2.b, 2.c, and 2.f). Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Response time testing for the sensors as noted in Table 3.3.1-2 is not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Response time testing for sensors are not required based on the analysis in NEDO-32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.3.2 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3.A REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

3/4.3.3

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

if they will be isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC)," and the definition of DRAIN TIME. There are functions that are required for manual initiation or operation of the ECCS injection/spray subsystem required to be OPERABLE by LCO 3.5.2 and other functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

The RPV Water Inventory Control Instrumentation supports operation of the Core Spray System (CSS) and the Low Pressure Coolant Injection (LPCI) system. The equipment involved with each of these systems is described in the Bases for LCO 3.5.2.

3/4.3.3 A double-ended guillotine break of the Reactor Coolant System (RCS) is not postulated in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is postulated in which a single operator error or initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure, e.g., seismic event, loss of normal power, or single human error. It is assumed, based on engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function-by-Function basis.

Core Spray Systems – Reactor Vessel Pressure – Low (Permissive) and Low Pressure Coolant Injection Mode of RHR System – Injection Valve Differential Pressure – Low (Permissive)

The low reactor vessel pressure signal for Core Spray and the injection valve low differential pressure signal for LPCI are used as permissives for the low pressure ECCS injection/spray subsystem manual injection functions. These functions ensure that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. While it is assured during OPERATIONAL CONDITIONS 4 and 5 that the reactor vessel pressure will be below the ECCS maximum design pressure, the Reactor Vessel Pressure - Low signal and the Injection Valve Differential Pressure – Low signal are assumed to be OPERABLE and capable of permitting initiation of the ECCS.

The Reactor Vessel Pressure - Low signals are initiated from four pressure transmitters that sense the reactor vessel pressure. The transmitters are connected to four trip units. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic.

INSTRUMENTATION

BASES

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

The Injection Valve Differential Pressure - Low signals are initiated from four differential pressure transmitters (one per valve) that monitor the differential pressure across each LPCI injection valve.

3/4.3.3

The Allowable Values are low enough to prevent overpressuring the equipment in the low pressure ECCS. The instrument channels of the Reactor Vessel Pressure - Low and Injection Valve Differential Pressure - Low Functions are required to be OPERABLE in OPERATIONAL CONDITIONS 4 and 5 when ECCS manual initiation is required to be OPERABLE by LCO 3.5.2.

Manual Initiation

The Manual Initiation push button channels introduce signals into the appropriate ECCS logic to provide manual initiation capability. There is one push button for each of the CSS and LPCI subsystems (i.e., four for CSS and four for LPCI).

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons. A channel of the Manual Initiation Function (one channel per subsystem) is required to be OPERABLE in OPERATIONAL CONDITIONS 4 and 5 when the associated ECCS subsystems are required to be OPERABLE per LCO 3.5.2.

RHR System Isolation - Reactor Vessel Water Level Low - Level 3

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level Low - Level 3 Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level Low - Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level Low - Level 3 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level Low - Level 3 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level Low - Level 3 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level Low - Level 3 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 2 valves.

Reactor Water Cleanup (RWCU) System Isolation - Reactor Vessel Water Level - Low, Low - Level 2

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level - Low, Low - Level 2 Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

Reactor Vessel Water Level – Low, Low – Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level - Low, Low - Level 2 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

3/4.3.3

The Reactor Vessel Water Level – Low, Low - Level 2 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level – Low, Low Level 2 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level – Low, Low - Level 2 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 3 valves.

Actions

A note has been provided to modify the ACTIONs related to RPV Water Inventory Control instrumentation channels. The ACTIONs for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for each inoperable RPV Water Inventory Control instrumentation channel.

ACTION a. directs taking the appropriate ACTION referenced in Table 3.3.3.A-1. The applicable ACTION referenced in the table is Function dependent.

RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level Low - Level 3, and Reactor Water Cleanup System Isolation, Reactor Vessel Water Level – Low, Low - Level 2 functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. If the instrumentation is inoperable, ACTION 38 directs an immediate declaration that the associated penetration flow path(s) are incapable of automatic isolation and calculation of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

Low reactor vessel pressure signals are used as permissives for the low pressure ECCS injection/spray subsystem manual injection functions. If the permissive is inoperable, manual initiation of ECCS is prohibited. Therefore, the permissive must be placed in the trip condition within 1 hour. With the permissive in the trip condition, manual initiation may be performed. Prior to placing the permissive in the tripped condition, the operator can take manual control of the pump and the injection valve to inject water into the RPV.

The allowed outage time of 1 hour is intended to allow the operator time to evaluate any discovered inoperabilities and to place the channel in trip.

The 24 hour allowed outage time was chosen to allow time for the operator to evaluate and repair any discovered inoperabilities. The allowed outage time is appropriate given the ability to manually start the ECCS pumps and open the injection valves and to manually ensure the pump does not overheat.

With the ACTION and associated allowed outage time of ACTION 39 or 40 not met, the associated low pressure ECCS injection/spray subsystem may be incapable of performing the intended function, and must be declared inoperable immediately.

PTS Bases INSTRUMENTATION

BASES

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81 "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3/4.3.3

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

3/4.3.4.1 The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order 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.

Specification 3/4.3.2, Plant Protection System Divisions

Unit 1

Current Technical Specifications Markup

3/4.3.2 PLANT PROTECTION SYSTEM DIVISIONS

PTS 3/4.3 INSTRUMENTATION

~~3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

INSERT 1

D04 D01

LIMITING CONDITION FOR OPERATION

3.3.1 4.3.2.1 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.~~ D02

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

Note: Separate condition entry is allowed for each channel.

Note: When Functional Unit 2.b and 2.c channels are inoperable due to the calculated power exceeding the APRM output by more than 2% of RATED THERMAL POWER while operating at ≥ 25% of RATED THERMAL POWER, entry into the associated Actions may be delayed up to 2 hours.

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

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

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

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.

---

*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.

Specification 3/4.3.2

Insert 1

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

   1. With one or more reactor trip divisions inoperable, within 6 hours:
      a. Place the associated reactor trip units in the tripped condition, or
      b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.
   2. With one or more non-reactor trip divisions inoperable, within 6 hours:
      a. Declare the associated equipment inoperable, or
      b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

b. In OPERATIONAL CONDITION 4:
   1. With one or more reactor trip divisions inoperable , within 1 hour:
      a. Verify all insertable control rods are inserted in the core*, and,
      b. Lock the Reactor Mode Switch in the Shutdown position.
   2. With one or more non-reactor trip divisions inoperable, within 1 hour:
      a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
      b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

c. In OPERATIONAL CONDITION 5:
   1. With one or more reactor trip divisions inoperable, within 1 hour:
      a. Verify all insertable control rods are inserted in the core*, and
      b. Suspend all operations involving CORE ALTERATIONS.
   2. With one or more non-reactor trip divisions inoperable, within 1 hour:
      a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
      b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

Insert 2

D02 D05

3.3.1

4.3.1.1 Each reactor protection system 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 4.3.1.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.1.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program, except Table 4.3.1.1-1 Functions 2.a, 2.b, 2.c, 2.d, 2.e and 2.f. Functions 2.a, 2.b, 2.c, 2.d, and 2.f do not require separate LOGIC SYSTEM FUNCTIONAL TESTS. For Function 2.e, tests shall be performed in accordance with the Surveillance Frequency Control Program. LOGIC SYSTEM FUNCTIONAL TEST for Function 2.e includes simulating APRM and OPRM trip conditions at the APRM channel inputs to the voter channel to check all combinations of two tripped inputs to the 2-Out-Of-4 voter logic in the voter channels.

4.3.2.1

~~4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its 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 reactor trip system~~.

D02

Specification 3/4.3.2

Insert 2

4.3.2.1 - The PLANT PROTECTION SYSTEM RESPONSE TIME of each division shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program.

4.3.2.2 - Verify that each Division provides a scram signal to all reactor trip components in accordance with the Surveillance Frequency Control Program.

~~TABLE 3.3.1-2~~

~~REACTOR PROTECTION SYSTEM RESPONSE TIMES~~

~~FUNCTIONAL UNIT~~	~~RESPONSE TIME (Seconds)~~
~~1. Intermediate Range Monitors:~~	
~~a. Neutron Flux - High~~	~~N.A.~~
~~b. Inoperative~~	~~N.A.~~
~~2. Average Power Range Monitor*:~~	
~~a. Neutron Flux - Upscale (Setdown)~~	~~N.A.~~
~~b. Simulated Thermal Power - Upscale~~	~~N.A.~~
~~c. Neutron Flux - Upscale~~	~~N.A.~~
~~d. Inoperative~~	~~N.A.~~
~~e. 2-Out-Of-4 Voter~~	~~≤0.05*~~
~~f. OPRM Upscale~~	~~N.A.~~
~~3. Reactor Vessel Steam Dome Pressure - High~~	~~≤0.55~~
~~4. Reactor Vessel Water Level - Low, Level 3~~	~~≤1.05#~~
~~5. Main Steam Line Isolation Valve - Closure~~	~~≤0.06~~
~~6. DELETED~~	~~DELETED~~
~~7. Drywell Pressure - High~~	~~N.A.~~
~~8. Scram Discharge Volume Water Level - High~~	
~~a. Level Transmitter~~	~~N.A.~~
~~b. Float Switch~~	~~N.A.~~
~~9. Turbine Stop Valve - Closure~~	~~≤0.06~~
~~10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low~~	~~≤0.08**~~
~~11. Reactor Mode Switch Shutdown Position~~	~~N.A.~~
~~12. Manual Scram~~	~~N.A.~~

D02

~~* Neutron detectors, APRM channel and 2-Out-Of-4 Voter channel digital electronics are exempt from response time testing. Response time shall be measured from activation of the 2-Out-Of-4 Voter output relay. For applications of Specification 4.3.1.3, the redundant outputs from each 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8. Testing of OPRM and APRM outputs shall alternate.~~

~~** Measured from start of turbine control valve fast closure.~~

~~# Sensor is eliminated from response time testing for the RPS circuits. Response time testing and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required.~~

INSTRUMENTATION

~~3/4.3.2. ISOLATION ACTUATION INSTRUMENTATION~~

LIMITING CONDITION FOR OPERATION

3.3.1 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
4.3.2.1 Setpoint column of Table 3.3.2.-2 and ~~with ISOLATION SYSTEM RESPONSE TIME as shown in Table 3.3.2-3~~. D02

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:

3.3.1
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.

** Not applicable when trip capability is not maintained.

\# Not applicable for Function 7, Secondary Containment Isolation.

PTS

INSTRUMENTATION

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within 1 hour and take the ACTION required by Table 3.3.2-1.

3.3.1 SURVEILLANCE REQUIREMENTS

4.3.2.1 Each isolation 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 4.3.2.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.2.1-1.

3.3.1

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

~~4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shown in Table 3.3.2-3 shall be demonstrated to be within its 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 accordance with the Surveillance Frequency Control Program, where N is the total number of redundant channels in a specific isolation trip system.~~

4.3.2.1 D02

** The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition; if both systems have the same number of inoperable channels, place either trip system in the tripped condition.

3.3.1

PTS

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION (Continued)				
3.3.1 f. HPCI Pipe Routing Area Temperature - High	L	4	1, 2, 3	23
g. Manual Initiation	NA(e)	1/system	1, 2, 3	24
~~h. HPCI Steam Line Δ Press Timer~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~23~~ D03
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High	K	1	1, 2, 3	23
b. RCIC Steam Supply Pressure - Low	KA	2	1, 2, 3	23
3.3.1 c. RCIC Turbine Exhaust Diaphragm Pressure - High	K	2	1, 2, 3	23
d. RCIC Equipment Room Temperature - High	K	1	1, 2, 3	23
e. RCIC Equipment Room Δ Temperature - High	K	1	1, 2, 3	23
f. RCIC Pipe Routing Area Temperature - High	K	5	1, 2, 3	23
g. Manual Initiation	NA(e)	1/system	1, 2, 3	24
~~h. RCIC Steam Line Δ Pressure Timer~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~23~~ D03

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION
ACTION STATEMENTS

ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24-hours.

3.3.1 ACTION 21 - Be in at least STARTUP with the associated penetration flow path(s) isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 6 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 22 - Be in at least STARTUP within 6 hours.

~~ACTION 23 - In OPERATIONAL CONDITION 1 or 2, verify the affected penetration flow path(s) are isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour and declare the affected system inoperable. In OPERATIONAL CONDITION 3, be in at least COLD SHUTDOWN within 12 hours.~~ D03

ACTION 24 - Restore the manual initiation function to OPERABLE status within 8 hours or isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within the next hour and declare the affected system inoperable or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 25 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

ACTION 26 - Isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour.

ACTION 27 - Restore the manual initiation function to OPERABLE status within 8 hours or establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3.3.1

TABLE NOTATIONS

* Required when handling RECENTLY IRRADIATED FUEL in the secondary containment.

** May be bypassed under administrative control, with all turbine stop valves closed.

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

\# During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

(a) DELETED

(b) 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 provided at least one OPERABLE channel in the same trip system is monitoring that parameter. Trip functions common to RPS Actuation Instrumentation are shown in Table 4.3.2.1-1. In addition, for the HPCI system and RCIC system isolation, provided that the redundant isolation valve, inboard or outboard, as applicable, in each line is OPERABLE and all required actuation instrumentation for that valve is OPERABLE, one channel may be placed in an inoperable status for up to 8 hours for required surveillance without placing the channel or trip system in the tripped condition.

PTS

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION		TRIP SETPOINT	ALLOWABLE VALUE
3.	REACTOR WATER CLEANUP SYSTEM ISOLATION		
a.	RWCS Δ Flow - High	≤ 54.9 gpm	≤ 65.2 gpm
b.	RWCS Area Temperature - High	≤ 155°F or ≤ 120°F**	≤ 160°F or ≤ 125°F**
c.	RWCS Area Ventilation Δ Temperature - High	≤ 52°F or ≤ 32°F**	≤ 60°F or ≤ 40°F**
d.	SLCS Initiation	N.A.	N.A.
e.	Reactor Vessel Water Level - Low, Low, - Level 2	≥ -38 inches *	≥ -45 inches
f.	Manual Initiation	N.A.	N.A.
4.	HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION		
a.	HPCI Steam Line Δ Pressure - High	≤ 974" H_2O	≤ 984" H_2O
b.	HPCI Steam Supply Pressure - Low	≥ 100 psig	≥ 90 psig
c.	HPCI Turbine Exhaust Diaphragm Pressure - High	≤ 10 psig	≤ 20 psig
d.	HPCI Equipment Room Temperature - High	180°F	≥ 177°F, ≤ 191°F
e.	HPCI Equipment Room Δ Temperature - High	≤ 104°F	≤ 108.5°F
f.	HPCI Pipe Routing Area Temperature - High	180°F	≥ 177°F, ≤ 191°F
g.	Manual Initiation	N.A.	N.A.
~~h.~~	~~HPCI Steam Line Δ Pressure - Timer~~	~~3 ≤ τ ≤ 12.5 seconds~~	~~2.5 ≤ τ ≤ 13 seconds~~

3.3.1

D03

PTS

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a. RCIC Steam Line Δ Pressure - High	≤ 373" H_2O	≤ 381" H_2O
b. RCIC Steam Supply Pressure - Low	≥ 64.5 psig	≥ 56.5 psig
3.3.1 c. RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10.0 psig	≤ 20.0 psig
d. RCIC Equipment Room Temperature - High	180°F	≥ 161°F, ≤ 191°F
e. RCIC Equipment Room Δ Temperature - High	≤ 109°F	≤ 113.5°F
f. RCIC Pipe Routing Area Temperature - High	180°F	≥ 161°F, ≤ 191°F
g. Manual Initiation	N.A.	N.A.
~~h. RCIC Steam Line Δ Pressure Timer~~	~~3 ≤ τ ≤ 12.5 seconds~~	~~2.5 ≤ τ ≤ 13 seconds~~ D03

~~TABLE 3.3.2-3~~

~~ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME~~

~~TRIP FUNCTION~~			~~RESPONSE TIME (Seconds)#~~
~~1.~~	~~MAIN STEAM LINE ISOLATION~~		
	~~a.~~	~~Reactor Vessel Water Level~~	
		~~1) Low, Low - Level 2~~	~~N.A.~~
		~~2) Low, Low, Low - Level 1~~	~~≤1.0 ###*~~
	~~b.~~	~~DELETED~~	~~DELETED~~
	~~c.~~	~~Main Steam Line Pressure - Low~~	~~≤1.0 ###*~~
	~~d.~~	~~Main Steam Line Flow - High~~	~~≤1.0 ###*~~
	~~e.~~	~~Condenser Vacuum - Low~~	~~N.A.~~
	~~f.~~	~~Outboard MSIV Room Temperature - High~~	~~N.A.~~
3.7.9	g.	Turbine Enclosure - Main Steam Line Tunnel Temperature - High	N.A.
	~~h.~~	~~Manual Initiation~~	~~N.A.~~
~~2.~~	~~RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION~~		
	~~a.~~	~~Reactor Vessel Water Level Low - Level 3~~	~~N.A.~~
	~~b.~~	~~Reactor Vessel (RHR Cut-In Permissive) Pressure - High~~	~~N.A.~~
	~~c.~~	~~Manual Initiation~~	~~N.A.~~
~~3.~~	~~REACTOR WATER CLEANUP SYSTEM ISOLATION~~		
	~~a.~~	~~RWCS Δ Flow - High~~	~~N.A.##~~
	~~b.~~	~~RWCS Area Temperature - High~~	~~N.A.~~
	~~c.~~	~~RWCS Area Ventilation Δ Temperature - High~~	~~N.A.~~
	~~d.~~	~~SLCS Initiation~~	~~N.A.~~
	~~e.~~	~~Reactor Vessel Water Level - Low, Low - Level 2~~	~~N.A.~~
	~~f.~~	~~Manual Initiation~~	~~N.A.~~

D02

D02

~~TABLE 3.3.2-3 (Continued)~~

~~ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME~~

~~TRIP FUNCTION~~	~~RESPONSE TIME (Seconds)#~~
~~4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION~~	
~~a. HPCI Steam Line Δ Pressure - High~~	~~N.A.~~
~~b. HPCI Steam Supply Pressure - Low~~	~~N.A.~~
~~c. HPCI Turbine Exhaust Diaphragm Pressure - High~~	~~N.A.~~
~~d. HPCI Equipment Room Temperature - High~~	~~N.A.~~
~~e. HPCI Equipment Room Δ Temperature - High~~	~~N.A.~~
~~f. HPCI Pipe Routing Area Temperature - High~~	~~N.A.~~
~~g. Manual Initiation~~	~~N.A.~~
~~5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION~~	
~~a. RCIC Steam Line Δ Pressure - High~~	~~N.A.~~
~~b. RCIC Steam Supply Pressure - Low~~	~~N.A.~~
~~c. RCIC Turbine Exhaust Diaphragm Pressure - High~~	~~N.A.~~
~~d. RCIC Equipment Room Temperature - High~~	~~N.A.~~
~~e. RCIC Equipment Room Δ Temperature - High~~	~~N.A.~~
~~f. RCIC Pipe Routing Area Temperature - High~~	~~N.A.~~
~~g. Manual Initiation~~	~~N.A.~~

D02

~~TABLE 3.3.2-3 (Continued)~~

~~ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME~~

~~TRIP FUNCTION~~	~~RESPONSE TIME (Seconds)#~~
~~6. PRIMARY CONTAINMENT ISOLATION~~	
~~a. Reactor Vessel Water Level~~	
~~1) Low, Low - Level 2~~	~~N.A.~~
~~2) Low, Low, Low - Level 1~~	~~N.A.~~
~~b. Drywell Pressure - High~~	~~N.A.~~
~~c. North Stack Effluent Radiation - High~~	~~N.A.~~
~~d. Deleted~~	
~~e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High~~	~~N.A.~~
~~f. Deleted~~	
~~g. Deleted~~	
~~h. Drywell Pressure - High/ Reactor Pressure - Low~~	~~N.A.~~
~~i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low~~	~~N.A.~~
~~j. Manual Initiation~~	~~N.A.~~
~~7. SECONDARY CONTAINMENT ISOLATION~~	
~~a. Reactor Vessel Water Level Low, Low - Level 2~~	~~N.A.~~
~~b. Drywell Pressure - High~~	~~N.A.~~
~~c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High~~	~~N.A.~~
~~2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High~~	~~N.A.~~
~~d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High~~	~~N.A.~~
~~e. Deleted~~	

D02

~~TABLE 3.3.2-3 (Continued)~~

~~ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME~~

~~TRIP FUNCTION~~		~~RESPONSE TIME (Seconds)#~~
~~f.~~	~~Deleted~~	
~~g.~~	~~Reactor Enclosure Manual Initiation~~	~~N.A.~~
~~h.~~	~~Refueling Area Manual Initiation~~	~~N.A.~~

~~TABLE NOTATIONS~~

D02

~~(a)~~ ~~DELETED~~

~~(b)~~ ~~DELETED~~

~~*~~ ~~Isolation system instrumentation response time for MSIV only. No diesel generator delays assumed for MSIVs.~~

~~**~~ ~~DELETED~~

~~#~~ ~~Isolation system instrumentation response time specified for the Trip Function actuating each valve group shall be added to the isolation time for the valves in each valve group to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.~~

~~##~~ ~~With 45 second time delay.~~

~~###~~ ~~Sensor is eliminated from response time testing for the MSIV actuation logic circuits. Response time testing and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required.~~

PTS

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
3. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCS Δ Flow - High				1, 2, 3
b. RWCS Area Temperature - High				1, 2, 3
c. RWCS Area Ventilation Δ Temperature - High				1, 2, 3
d. SLCS Initiation	N.A.		N.A.	1, 2, 3
e. Reactor Vessel Water Level Low, Low, - Level 2				1, 2, 3
f. Manual Initiation	N.A.		N.A.	1, 2, 3
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High				1, 2, 3
b. HPCI Steam Supply Pressure, Low				1, 2, 3
c. HPCI Turbine Exhaust Diaphragm Pressure - High				1, 2, 3
d. HPCI Equipment Room Temperature - High				1, 2, 3
e. HPCI Equipment Room Δ Temperature - High				1, 2, 3
f. HPCI Pipe Routing Area Temperature - High				1, 2, 3
g. Manual Initiation	N.A.		N.A.	1, 2, 3
~~h. HPCI Steam Line Δ Pressure Timer~~	~~N.A.~~			~~1, 2, 3~~

3.3.1

D03

PTS

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High				1, 2, 3
3.3.1 b. RCIC Steam Supply Pressure - Low				1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High				1, 2, 3
d. RCIC Equipment Room Temperature - High				1, 2, 3
e. RCIC Equipment Room Δ Temperature - High				1, 2, 3
f. RCIC Pipe Routing Area Temperature - High				1, 2, 3
g. Manual Initiation	N.A.		N.A.	1, 2, 3
~~h. RCIC Steam Line Δ Pressure Timer~~	~~N.A.~~			~~1, 2, 3~~ D03

PTS INSTRUMENTATION

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 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

4.3.2.1 ~~and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.~~ D02

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.

3.3.1

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
3.3.1 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~~
4.3.2.1 ~~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.~~ D02

PTS

TABLE 3.3.3-1 (Continued)

3.3.1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

	TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[(a)]	APPLICABLE OPERATIONAL CONDITIONS	ACTION	
3.3.1	4. AUTOMATIC DEPRESSURIZATION SYSTEM#***				
3.3.1	a. Reactor Vessel Water Level - Low Low Low, Level 1	2	1, 2, 3	30	
	b. Drywell Pressure - High	2	1, 2, 3	30	
	~~c. ADS Timer~~	~~1~~	~~1, 2, 3~~	~~31~~	D03
	d. Core Spray Pump Discharge Pressure - High (Permissive)	2	1, 2, 3	31	
	e. RHR LPCI Mode Pump Discharge Pressure High (Permissive)	4	1, 2, 3	31	
3.3.1	f. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31	
	g. Manual Initiation	2	1, 2, 3	33	
	~~h. ADS Drywell Pressure Bypass Timer~~	~~2~~	~~1, 2, 3~~	~~31~~	D03

		TOTAL NO. OF CHANNELS(f)	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
3.3.5	5. LOSS OF POWER					
	1. 4.16 Kv Emergency Bus Under-voltage (Loss of Voltage)	1/bus	1/bus	1/bus	1,2,3,4**,5**	36
	2. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	1/source/ bus	1/source/ bus	1/source/ bus	1,2,3,4**,5**	37

3.3.1 ***The Minimum OPERABLE Channels Per Trip Function is per subsystem.

PTS

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:

3.3.1

a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or in accordance with the Risk Informed Completion Time Program, 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.~~ D03

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

3.3.1

a. For one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or in accordance with the Risk Informed Completion Time Program, 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 in accordance with the Risk Informed Completion Time Program*, 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.

3.3.5

3.3.1

*Not applicable when trip capability is not maintained.

PTS

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

ACTION 37 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable device in the bypassed condition subject to the following conditions:

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable. 127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

3.3.5

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. CORE SPRAY SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Reactor Vessel Pressure - Low	≥ 455 psig,(decreasing)	≥ 435 psig, (decreasing)
d. Manual Initiation	N.A.	N.A.
3.3.1 2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Reactor Vessel Pressure - Low	≥ 455 psig,(decreasing)	≥ 435 psig, (decreasing)
d. Injection Valve Differential Pressure - Low	≥ 74 psid, (decreasing)	≥ 64 psid and ≤ 84 psid
e. Manual Initiation	N.A.	N.A.
3. HIGH PRESSURE COOLANT INJECTION SYSTEM		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -38 inches*	≥ -45 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Condensate Storage Tank Level - Low	≥ 167.8 inches**	≥ 164.3 inches
d. Suppression Pool Water Level - High	≤ 24 feet 1.5 inches	≤ 24 feet 3 inches
e. Reactor Vessel Water Level - High, Level 8	≤ 54 inches	≤ 60 inches
f. Manual Initiation	N.A.	N.A.
4. AUTOMATIC DEPRESSURIZATION SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
~~c. ADS Timer~~	~~≤ 105 seconds~~	~~≤ 117 seconds~~ D03
d. Core Spray Pump Discharge Pressure - High	≥ 145 psig,(increasing)	≥ 125 psig, (increasing),
3.3.1 e. RHR LPCI Mode Pump Discharge Pressure-High	≥ 125 psig,(increasing)	≥ 115 psig, (increasing)
f. Reactor Vessel Water Level-Low, Level 3	≥ 12.5 inches	≥ 11.0 inches
g. Manual Initiation	N.A.	N.A.
~~h. ADS Drywell Pressure Bypass Timer~~	~~≤ 420 seconds~~	~~≤ 450 seconds~~ D03

~~*See Bases Figure B 3/4.3-1.~~

3.3.1 ~~**Corresponds~~ to 2.3 feet indicated.

~~TABLE 3.3.3-2 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS~~

TRIP FUNCTION		TRIP SETPOINT		ALLOWABLE VALUE
5. LOSS OF POWER	RELAY			
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X	NA		NA
3.3.5 b. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	RELAY 127-11XOX and 102-11XOX	a.	4.16 kV Basis 2905 ± 115 volts	2905 ± 145 volts
		b.	120 V Basis 83 ± 3 volts	83 ± 4 volts
		c.	≤ 1 second time delay	≤ 1.5 second time delay
	127Y-11XOX** and 127Y-1-11XOX	a.	4.16 kV Basis 3640 ± 91 volts	3640 ± 182 volts
		b.	120 V Basis 104 ± 3 volts	104 ± 5.2 volts
		c.	≤ 52 second time delay	≤ 60 second time delay
	127Z-11XOX and 162Y-11XOX	a.	4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b.	120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c.	≤ 10 second time delay	≤ 11 second time delay
	127Z-11XOX and 162Z-11XOX	a.	4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b.	120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c.	≤ 61 second time delay	≤ 64 second time delay

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

PTS

~~TABLE 3.3.3-3~~

~~EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES~~

	~~ECCS~~	~~RESPONSE TIME (Seconds)~~	
3.3.2 Bases	~~1.~~ ~~CORE SPRAY SYSTEM~~	~~≤ 27#~~	
	~~2.~~ ~~LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM~~	~~≤ 40#~~	D02
	~~3.~~ ~~AUTOMATIC DEPRESSURIZATION SYSTEM~~	~~N.A.~~	
	~~4.~~ ~~HIGH PRESSURE COOLANT INJECTION SYSTEM~~	~~≤ 60#~~	
3.3.5	5. LOSS OF POWER	N.A.	

\# ~~ECCS actuation instrumentation is eliminated from response time testing.~~ D02

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED	
	4. AUTOMATIC DEPRESSURIZATION SYSTEM#					
3.3.1	a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3	
	b. Drywell Pressure - High				1, 2, 3	
	~~c. ADS Timer~~	~~N.A.~~			~~1, 2, 3~~	D03
3.3.1	d. Core Spray Pump Discharge Pressure - High				1, 2, 3	
	e. RHR LPCI Mode Pump Discharge Pressure - High				1, 2, 3	
	f. Reactor Vessel Water Level - Low, Level 3				1, 2, 3	
	g. Manual Initiation	N.A.		N.A.	1, 2, 3	
	~~h. ADS Drywell Pressure Bypass Timer~~	~~N.A.~~			~~1, 2, 3~~	D03
	5. LOSS OF POWER					
3.3.5	a. 4.16 kV Emergency Bus Under-voltage (Loss of Voltage)##	N.A.		N.A.	1, 2, 3, 4**, 5**	
	b. 4.16 kV Emergency Bus Under - voltage (Degraded Voltage)				1, 2, 3, 4**, 5**	

3.3.1 (a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

* DELETED

3.3.5 ** Required OPERABLE when ESF equipment is required to be OPERABLE.

3.3.1 *** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

3.3.5 ## Loss of Voltage Relay 127-11X is not field setable.

Unit 2

Current Technical Specifications Markup

PTS

3/4.3.2 PLANT PROTECTION SYSTEM DIVISIONS

3/4.3 INSTRUMENTATION

~~3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

Insert 1

D01

D04

LIMITING CONDITION FOR OPERATION

D02

3.3.1 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.~~

4.3.2.1

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

Note: Separate condition entry is allowed for each channel.

Note: When Functional Unit 2.b and 2.c channels are inoperable due the calculated power exceeding the APRM output by more than 2% of RATED THERMAL POWER while operating at ≥ 25% of RATED THERMAL POWER, entry into the associated Actions may be delayed up to 2 hours.

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

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

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

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.

* 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.

Specification 3/4.3.2

Insert 1

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

   1. With one or more reactor trip divisions inoperable, within 6 hours:
      a. Place the associated reactor trip units in the tripped condition, or
      b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.
   2. With one or more non-reactor trip divisions inoperable, within 6 hours:
      a. Declare the associated equipment inoperable, or
      b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

b. In OPERATIONAL CONDITION 4:
   1. With one or more reactor trip divisions inoperable , within 1 hour:
      a. Verify all insertable control rods are inserted in the core*, and,
      b. Lock the Reactor Mode Switch in the Shutdown position.
   2. With one or more non-reactor trip divisions inoperable, within 1 hour:
      a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
      b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

c. In OPERATIONAL CONDITION 5:
   1. With one or more reactor trip divisions inoperable, within 1 hour:
      a. Verify all insertable control rods are inserted in the core*, and
      b. Suspend all operations involving CORE ALTERATIONS.
   2. With one or more non-reactor trip divisions inoperable, within 1 hour:
      a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
      b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

Insert 2

D02 D05

SURVEILLANCE REQUIREMENTS

3.3.1 4.3.1.1 Each reactor protection system 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 4.3.1.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.1.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program, except Table 4.3.1.1-1 Functions 2.a, 2.b, 2.c, 2.d, 2.e, and 2.f. Functions 2.a, 2.b, 2.c, 2.d, and 2.f do not require separate LOGIC SYSTEM FUNCTIONAL TESTS. For Function 2.e, tests shall be performed in accordance with the Surveillance Frequency Control Program. LOGIC SYSTEM FUNCTIONAL TEST for Function 2.e includes simulating APRM and OPRM trip conditions at the APRM channel inputs to the voter channel to check all combinations of two tripped inputs to the 2-Out-Of-4 voter logic in the voter channels.

4.3.2.1 ~~4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its 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 reactor trip system.~~

D02

Specification 3/4.3.2

Insert 2

4.3.2.1 - The PLANT PROTECTION SYSTEM RESPONSE TIME of each division shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program.

4.3.2.2 - Verify that each Division provides a scram signal to all reactor trip components in accordance with the Surveillance Frequency Control Program.

PTS 3.3.2 Bases

~~TABLE 3.1-2~~

~~REACTOR PROTECTION SYSTEM RESPONSE TIMES~~

~~FUNCTIONAL UNIT~~	~~RESPONSE TIME (Seconds)~~
~~1. Intermediate Range Monitors:~~	
~~a. Neutron Flux - High~~	~~N.A.~~
~~b. Inoperative~~	~~N.A.~~
~~2. Average Power Range Monitor*:~~	
~~a. Neutron Flux - Upscale (Setdown)~~	~~N.A.~~
~~b. Simulated Thermal Power - Upscale~~	~~N.A.~~
~~c. Neutron Flux - Upscale~~	~~N.A.~~
~~d. Inoperative~~	~~N.A.~~
~~e. 2-Out-Of-4 Voter~~	~~≤0.05*~~
~~f. OPRM Upscale~~	~~N.A.~~
~~3. Reactor Vessel Steam Dome Pressure - High~~	~~≤0.55~~
~~4. Reactor Vessel Water Level - Low, Level 3~~	~~≤1.05#~~
~~5. Main Steam Line Isolation Valve - Closure~~	~~≤0.06~~
~~6. DELETED~~	~~DELETED~~
~~7. Drywell Pressure - High~~	~~N.A.~~
~~8. Scram Discharge Volume Water Level - High~~	
~~a. Level Transmitter~~	~~N.A.~~
~~b. Float Switch~~	~~N.A.~~
~~9. Turbine Stop Valve - Closure~~	~~≤0.06~~
~~10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low~~	~~≤0.08**~~
~~11. Reactor Mode Switch Shutdown Position~~	~~N.A.~~
~~12. Manual Scram~~	~~N.A.~~

D02

~~* Neutron detectors, APRM channel and 2-Out-Of-4 Voter channel digital electronics are exempt from response time testing. Response time shall be measured from activation of the 2-Out-Of-4 Voter output relay. For application of Specification 4.3.1.3, the redundant outputs from each 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8. Testing of OPRM and APRM outputs shall alternate.~~

~~** Measured from start of turbine control valve fast closure.~~

~~# Sensor is eliminated from response time testing for the RPS circuits. Response time testing and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required.~~

PTS

INSTRUMENTATION

~~3/4.3.2. ISOLATION ACTUATION INSTRUMENTATION~~

LIMITING CONDITION FOR OPERATION

3.3.1 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~~ D02

4.3.2.1 ~~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:

3.3.1 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.

** Not applicable when trip capability is not maintained.

\# Not applicable for Function 7, Secondary Containment Isolation.

INSTRUMENTATION

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within 1 hour and take the ACTION required by Table 3.3.2-1.

3.3.1 SURVEILLANCE REQUIREMENTS

4.3.2.1 Each isolation 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 4.3.2.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.2.1-1.

3.3.1

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

4.3.2.1 ~~4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shown in Table 3.3.2-3 shall be demonstrated to be within its 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 isolation trip system.~~ D02

3.3.1 ** The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition; if both systems have the same number of inoperable channels, place either trip system in the tripped condition.

PTS

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION (Continued)				
3.3.1 f. HPCI Pipe Routing Area Temperature - High	L	4	1, 2, 3	23
g. Manual Initiation	NA(e)	1/system	1, 2, 3	24
~~h. HPCI Steam Line Δ Press Timer~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~23~~ D03
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High	K	1	1, 2, 3	23
b. RCIC Steam Supply Pressure - Low	KA	2	1, 2, 3	23
c. RCIC Turbine Exhaust Diaphragm Pressure - High	K	2	1, 2, 3	23
3.3.1 d. RCIC Equipment Room Temperature - High	K	1	1, 2, 3	23
e. RCIC Equipment Room Δ Temperature - High	K	1	1, 2, 3	23
f. RCIC Pipe Routing Area Temperature - High	K	4	1, 2, 3	23
g. Manual Initiation	NA(e)	1/system	1, 2, 3	24
~~h. RCIC Steam Line Δ Pressure Timer~~	~~NA~~	~~1~~	~~1, 2, 3~~	~~23~~ D03

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION
ACTION STATEMENTS

ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

3.3.1 ACTION 21 - Be in at least STARTUP with the associated penetration flow path(s) isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 6 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 22 - Be in at least STARTUP within 6 hours.

~~ACTION 23 - In OPERATIONAL CONDITION 1 or 2, verify the affected penetration flow path(s) are isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour and declare the affected system inoperable. In OPERATIONAL CONDITION 3, be in at least COLD SHUTDOWN within 12 hours.~~ D03

ACTION 24 - Restore the manual initiation function to OPERABLE status within 8 hours or isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within the next hour and declare the affected system inoperable or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 25 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

ACTION 26 - Isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour.

3.3.1 ACTION 27 - Restore the manual initiation function to OPERABLE status within 8 hours or establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

TABLE NOTATIONS

* Required when handling RECENTLY IRRADIATED FUEL in the secondary containment.

** May be bypassed under administrative control, with all turbine stop valves closed.

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

\# During operation of the associated Unit 1 or Unit 2 ventilation exhaust system.

(a) DELETED

(b) 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 provided at least one OPERABLE channel in the same trip system is monitoring that parameter. Trip functions common to RPS Actuation Instrumentation are shown in Table 4.3.2.1-1. In addition, for the HPCI system and RCIC system isolation, provided that the redundant isolation valve, inboard or outboard, as applicable, in each line is OPERABLE and all required actuation instrumentation for that valve is OPERABLE, one channel may be placed in an inoperable status for up to 8 hours for required surveillance without placing the channel or trip system in the tripped condition.

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE	
3. REACTOR WATER CLEANUP SYSTEM ISOLATION			
a. RWCS Δ Flow - High	≤ 54.9 gpm	≤ 65.2 gpm	
b. RWCS Area Temperature - High	≤ 155°F or ≤ 120°F**	≤ 160°F or ≤ 125°F**	
c. RWCS Area Ventilation Δ Temperature - High	≤ 52°F or ≤ 32°F**	≤ 60°F or ≤ 40°F**	
d. SLCS Initiation	N.A.	N.A.	
e. Reactor Vessel Water Level - Low, Low, - Level 2	≥ -38 inches *	≥ -45 inches	
3.3.1 f. Manual Initiation	N.A.	N.A.	
4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION			
a. HPCI Steam Line Δ Pressure - High	≤ 974" H_2O	≤ 984" H_2O	
b. HPCI Steam Supply Pressure - Low	≥ 100 psig	≥ 90 psig	
c. HPCI Turbine Exhaust Diaphragm Pressure - High	≤ 10 psig	≤ 20 psig	
d. HPCI Equipment Room Temperature - High	180°F	≥ 177°F, ≤ 191°F	
e. HPCI Equipment Room Δ Temperature - High	≤ 104°F	≤ 108.5°F	
f. HPCI Pipe Routing Area Temperature - High	180°F	≥ 177°F, ≤ 191°F	
g. Manual Initiation	N.A.	N.A.	
~~h. HPCI Steam Line Δ Pressure - Timer~~	~~3 ≤ τ ≤ 12.5 seconds~~	~~2.5 ≤ τ ≤ 13 seconds~~	D03

PTS

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a. RCIC Steam Line Δ Pressure - High	≤ 373" H_2O	≤ 381" H_2O
3.3.1 b. RCIC Steam Supply Pressure - Low	≥ 64.5 psig	≥ 56.5 psig
c. RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10.0 psig	≤ 20.0 psig
d. RCIC Equipment Room Temperature - High	180°F	≥ 161°F, ≤ 191°F
e. RCIC Equipment Room Δ Temperature - High	≤ 109°F	≤ 113.5°F
f. RCIC Pipe Routing Area Temperature - High	180°F	≥ 161°F, ≤ 191°F
g. Manual Initiation	N.A.	N.A.
~~h. RCIC Steam Line Δ Pressure Timer~~	~~3 ≤ τ ≤ 12.5 seconds~~	~~2.5 ≤ τ ≤ 13 seconds~~

D03

~~TABLE 3.3.2-3~~

~~ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME~~

~~TRIP FUNCTION~~			~~RESPONSE TIME (Seconds)#~~
~~1.~~	~~MAIN STEAM LINE ISOLATION~~		
	~~a.~~	~~Reactor Vessel Water Level~~	
		~~1) Low, Low - Level 2~~	~~N.A.~~
		~~2) Low, Low, Low - Level 1~~	~~≤1.0###*~~
	~~b.~~	~~DELETED~~	~~DELETED~~
	~~c.~~	~~Main Steam Line Pressure - Low~~	~~≤1.0###*~~
	~~d.~~	~~Main Steam Line Flow - High~~	~~≤1.0###*~~
	~~e.~~	~~Condenser Vacuum - Low~~	~~N.A.~~
	~~f.~~	~~Outboard MSIV Room Temperature - High~~	~~N.A.~~
3.7.9	g.	Turbine Enclosure - Main Steam Line Tunnel Temperature - High	N.A.
	h.	~~Manual Initiation~~	N.A.
~~2.~~	~~RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION~~		
	~~a.~~	~~Reactor Vessel Water Level Low - Level 3~~	~~N.A.~~
	~~b.~~	~~Reactor Vessel (RHR Cut In Permissive) Pressure - High~~	~~N.A.~~
	~~c.~~	~~Manual Initiation~~	~~N.A.~~
~~3.~~	~~REACTOR WATER CLEANUP SYSTEM ISOLATION~~		
	~~a.~~	~~RWCS Δ Flow - High~~	~~N.A.##~~
	~~b.~~	~~RWCS Area Temperature - High~~	~~N.A.~~
	~~c.~~	~~RWCS Area Ventilation Δ Temperature - High~~	~~N.A.~~
	~~d.~~	~~SLCS Initiation~~	~~N.A.~~
	~~e.~~	~~Reactor Vessel Water Level - Low, Low - Level 2~~	~~N.A.~~
	~~f.~~	~~Manual Initiation~~	~~N.A.~~

D02

D02

~~TABLE 3.3.2-3 (Continued)~~

~~ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME~~

~~TRIP FUNCTION~~	~~RESPONSE TIME (Seconds)#~~
~~4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION~~	
~~a. HPCI Steam Line Δ Pressure - High~~	~~N.A.~~
~~b. HPCI Steam Supply Pressure - Low~~	~~N.A.~~
~~c. HPCI Turbine Exhaust Diaphragm Pressure - High~~	~~N.A.~~
~~d. HPCI Equipment Room Temperature - High~~	~~N.A.~~
~~e. HPCI Equipment Room Δ Temperature - High~~	~~N.A.~~
~~f. HPCI Pipe Routing Area Temperature - High~~	~~N.A.~~
~~g. Manual Initiation~~	~~N.A.~~
~~5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION~~	
~~a. RCIC Steam Line Δ Pressure - High~~	~~N.A.~~
~~b. RCIC Steam Supply Pressure - Low~~	~~N.A.~~
~~c. RCIC Turbine Exhaust Diaphragm Pressure - High~~	~~N.A.~~
~~d. RCIC Equipment Room Temperature - High~~	~~N.A.~~
~~e. RCIC Equipment Room Δ Temperature - High~~	~~N.A.~~
~~f. RCIC Pipe Routing Area Temperature - High~~	~~N.A.~~
~~g. Manual Initiation~~	~~N.A.~~

D02

~~TABLE 3.3.2-3 (Continued)~~

~~ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME~~

~~TRIP FUNCTION~~	~~RESPONSE TIME (Seconds)#~~
~~6. PRIMARY CONTAINMENT ISOLATION~~	
~~a. Reactor Vessel Water Level~~	
~~1) Low, Low - Level 2~~	~~N.A.~~
~~2) Low, Low, Low - Level 1~~	~~N.A.~~
~~b. Drywell Pressure - High~~	~~N.A.~~
~~c. North Stack Effluent Radiation - High~~	~~N.A.~~
~~d. Deleted~~	
~~e. Reactor Enclosure Ventilation Exhaust Duct - Radiation - High~~	~~N.A.~~
~~f. Deleted~~	
~~g. Deleted~~	
~~h. Drywell Pressure - High/ Reactor Pressure - Low~~	~~N.A.~~
~~i. Primary Containment Instrument Gas to Drywell Δ Pressure - Low~~	~~N.A.~~
~~j. Manual Initiation~~	~~N.A.~~
~~7. SECONDARY CONTAINMENT ISOLATION~~	
~~a. Reactor Vessel Water Level Low, Low - Level 2~~	~~N.A.~~
~~b. Drywell Pressure - High~~	~~N.A.~~
~~c.1. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High~~	~~N.A.~~
~~2. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High~~	~~N.A.~~
~~d. Reactor Enclosure Ventilation Exhaust Duct Radiation - High~~	~~N.A.~~
~~e. Deleted~~	

D02

~~TABLE 3.3.2-3 (Continued)~~

~~ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME~~

~~TRIP FUNCTION~~		~~RESPONSE TIME (Seconds)#~~
~~f.~~	~~Deleted~~	
~~g.~~	~~Reactor Enclosure Manual Initiation~~	~~N.A.~~
~~h.~~	~~Refueling Area Manual Initiation~~	~~N.A.~~

~~TABLE NOTATIONS~~

D02

~~(a) DELETED~~

~~(b) DELETED~~

~~* Isolation system instrumentation response time for MSIV only. No diesel generator delays assumed for MSIVs.~~

~~** DELETED~~

~~# Isolation system instrumentation response time specified for the Trip Function actuating each valve group shall be added to the isolation time for the valves in each valve group to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.~~

~~## With 45 second time delay.~~

~~### Sensor is eliminated from response time testing for the MSIV actuation logic circuits. Response time testing and conformance to the administrative limits for the remaining channel including trip unit and relay logic are required.~~

Amendment No. 52, 74, 93, ~~10~~
OCT 1 2 2000

PTS

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
3. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCS Δ Flow - High				1, 2, 3
b. RWCS Area Temperature - High				1, 2, 3
c. RWCS Area Ventilation Δ Temperature - High				1, 2, 3
d. SLCS Initiation	N.A.		N.A.	1, 2, 3
e. Reactor Vessel Water Level Low, Low, - Level 2				1, 2, 3
f. Manual Initiation	N.A.		N.A.	1, 2, 3
3.3.1 4. HIGH PRESSURE COOLANT INJECTION SYSTEM ISOLATION				
a. HPCI Steam Line Δ Pressure - High				1, 2, 3
b. HPCI Steam Supply Pressure, Low				1, 2, 3
c. HPCI Turbine Exhaust Diaphragm Pressure - High				1, 2, 3
d. HPCI Equipment Room Temperature - High				1, 2, 3
e. HPCI Equipment Room Δ Temperature - High				1, 2, 3
f. HPCI Pipe Routing Area Temperature - High				1, 2, 3
g. Manual Initiation	N.A.		N.A.	1, 2, 3
~~h. HPCI Steam Line Δ Pressure Timer~~	~~N.A.~~			~~1, 2, 3~~

D03

PTS

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

3.3.1

TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure - High				1, 2, 3
b. RCIC Steam Supply Pressure - Low				1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High				1, 2, 3
d. RCIC Equipment Room Temperature - High				1, 2, 3
e. RCIC Equipment Room Δ Temperature - High				1, 2, 3
f. RCIC Pipe Routing Area Temperature - High				1, 2, 3
g. Manual Initiation	N.A.		N.A.	1, 2, 3
~~h.~~ ~~RCIC Steam Line Δ Pressure Timer~~	~~N.A.~~			~~1, 2, 3~~

D03

PTS INSTRUMENTATION

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 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
4.3.2.1 ~~and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.~~ D02

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:

3.3.1

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

3.3.1

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.

4.3.2.1 ~~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.~~ D02

PTS

3.3.1

LIMERICK - UNIT 2

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
3.3.1 4. AUTOMATIC DEPRESSURIZATION SYSTEM#***			
3.3.1 a. Reactor Vessel Water Level - Low Low Low, Level 1	2	1, 2, 3	30
b. Drywell Pressure - High	2	1, 2, 3	30 D03
~~c. ADS Timer~~	~~1~~	~~1, 2, 3~~	~~31~~
d. Core Spray Pump Discharge Pressure - High (Permissive)	2	1, 2, 3	31
3.3.1 e. RHR LPCI Mode Pump Discharge Pressure High (Permissive)	4	1, 2, 3	31
f. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
g. Manual Initiation	2	1, 2, 3	33 D03
~~h. ADS Drywell Pressure Bypass Timer~~	~~2~~	~~1, 2, 3~~	~~31~~

	TOTAL NO. OF CHANNELS(f)	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
3.3.5 5. LOSS OF POWER					
1. 4.16 kV Emergency Bus Under-voltage (Loss of Voltage)	1/bus	1/bus	1/bus	1, 2, 3, 4**, 5**	36
2. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	1/source/ bus	1/source/ bus	1/source/ bus	1, 2, 3, 4**, 5**	37

3.3.1 ***The Minimum OPERABLE Channels Per Trip Function is per subsystem.

PTS

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:

3.3.1 a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or in accordance with the Risk Informed Completion Time Program, 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.~~ D03

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

3.3.1 a. For one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or in accordance with the Risk Informed Completion Time Program, 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 in accordance with the Risk Informed Completion Time Program*, 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

3.3.5 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.

3.3.1 *Not applicable when trip capability is not maintained.

PTS

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

ACTION 37 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable device in the bypassed condition subject to the following conditions:

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable. 127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

3.3.5

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. CORE SPRAY SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Reactor Vessel Pressure - Low	≥ 455 psig,(decreasing)	≥ 435 psig, (decreasing)
d. Manual Initiation	N.A.	N.A.
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Reactor Vessel Pressure - Low	≥ 455 psig,(decreasing)	≥ 435 psig, (decreasing)
d. Injection Valve Differential Pressure - Low	≥ 74 psid, (decreasing)	≥ 64 psid and ≤ 84 psid
e. Manual Initiation	N.A.	N.A.
3. HIGH PRESSURE COOLANT INJECTION SYSTEM		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -38 inches*	≥ -45 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Condensate Storage Tank Level - Low	≥ 167.8 inches**	≥ 164.3 inches
d. Suppression Pool Water Level - High	≤ 24 feet 1.5 inches	≤ 24 feet 3 inches
e. Reactor Vessel Water Level - High, Level 8	≤ 54 inches	≤ 60 inches
f. Manual Initiation	N.A.	N.A.
4. AUTOMATIC DEPRESSURIZATION SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129 inches*	≥ -136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
~~c. ADS Timer~~	~~≤ 105 seconds~~	~~≤ 117 seconds~~
d. Core Spray Pump Discharge Pressure - High	≥ 145 psig,(increasing)	≥ 125 psig, (increasing),
e. RHR LPCI Mode Pump Discharge Pressure-High	≥ 125 psig,(increasing)	≥ 115 psig, (increasing)
f. Reactor Vessel Water Level-Low, Level 3	≥ 12.5 inches	≥ 11.0 inches
g. Manual Initiation	N.A.	N.A.
~~h. ADS Drywell Pressure Bypass Timer~~	~~≤ 420 seconds~~	~~≤ 450 seconds~~

D03

3.3.1

D03

3.3.1

~~*See Bases Figure B 3/4.3-1.~~

~~**Corresponds~~ to 2.3 feet indicated.

3.3.1

3.3.5

~~TABLE 3.3.3-2 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS~~

TRIP FUNCTION			TRIP SETPOINT	ALLOWABLE VALUE
5. LOSS OF POWER	RELAY			
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X		NA	NA
b. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	RELAY			
	127-11X0X and 102-11X0X	a.	4.16 kV Basis 2905 ± 115 volts	2905 ± 145 volts
		b.	120 V Basis 83 ± 3 volts	83 ± 4 volts
		c.	≤ 1 second time delay	≤ 1.5 second time delay
	127Y-11X0X** and 127Y-1-11X0X	a.	4.16 kV Basis 3640 ± 91 volts	3640 ± 182 volts
		b.	120 V Basis 104 ± 3 volts	104 ± 5.2 volts
		c.	≤ 52 second time delay	≤ 60 second time delay
	127Z-11X0X and 162Y-11X0X	a.	4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b.	120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c.	≤ 10 second time delay	≤ 11 second time delay
	127Z-11X0X and 162Z-11X0X	a.	4.16 kV Basis 3910 ± 11 volts	3910 ± 19 volts
		b.	120 V Basis 111.7 ± 0.3 volts	111.7 ± 0.5 volts
		c.	≤ 61 second time delay	≤ 64 second time delay

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

PTS

~~TABLE 3.3.3-3~~

~~EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES~~

~~ECCS~~		~~RESPONSE TIME (Seconds)~~
3.3.2 Bases	~~1. CORE SPRAY SYSTEM~~	≤ ~~27#~~
	~~2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM~~	~~≤ 40#~~
	~~3. AUTOMATIC DEPRESSURIZATION SYSTEM~~	~~N.A.~~
	~~4. HIGH PRESSURE COOLANT INJECTION SYSTEM~~	~~≤ 60#~~
3.3.5	5. LOSS OF POWER	N.A.

D02

~~# ECCS actuation instrumentation is eliminated from response time testing.~~

D02

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED	
	4. AUTOMATIC DEPRESSURIZATION SYSTEM#					
3.3.1	a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3	
	b. Drywell Pressure - High				1, 2, 3	
	~~c. ADS Timer~~	~~N.A.~~			~~1, 2, 3~~	D03
	d. Core Spray Pump Discharge Pressure - High				1, 2, 3	
3.3.1	e. RHR LPCI Mode Pump Discharge Pressure - High				1, 2, 3	
	f. Reactor Vessel Water Level - Low, Level 3				1, 2, 3	
	g. Manual Initiation	N.A.		N.A.	1, 2, 3	
	~~h. ADS Drywell Pressure Bypass Timer~~	~~N.A.~~			~~1, 2, 3~~	D03
	5. LOSS OF POWER					
3.3.5	a. 4.16 kV Emergency Bus Under voltage (Loss of Voltage)##	N.A.		N.A.	1, 2, 3, 4**, 5**	
	b. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)				1, 2, 3, 4**, 5**	

3.3.1 (a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

* DELETED

3.3.5 ** Required OPERABLE when ESF equipment is required to be OPERABLE.

3.3.1 *** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

3.3.5 ## Loss of Voltage Relay 127-11X is not field setable.

Discussion of Changes

Discussion of Changes

Technical Specification 3/4.3.2
Plant Protection System Divisions

D01

The existing requirements in current TSs 3.3.1, "Reactor Protection System Instrumentation," 3.3.2, "Isolation Actuation Instrumentation," and 3.3.3, Emergency Core Cooling System Actuation Instrumentation," related to coincidence logic and response time testing are combined into a new specification 3.3.2, "Plant Protection System Divisions."

As discussed in Section 3.2 of the PPS Licensing Technical Report, the PPS divisions are consistent with the IEEE Standard 603, definition of a division: "The designation applied to a given system or set of components that enables the establishment and maintenance of physical, electrical, and functional independence from other redundant sets of components." The proposed changes are acceptable because the relabeling of the existing requirements does not result in any technical changes.

D02

The current TS LCO 3.3.1 and SR 4.3.1.3 requirements to verify Reactor Protection System Response Time, the current TS LCO 3.3.2 and SR 4.3.2.3 requirement to verify the Isolation System Response Time, and the current TS LCO 3.3.3 and SR 4.3.3.3 requirement to verify ECCS Response Time are replaced with new surveillance 4.3.2.1, which requires the Plant Protection System Response Time of each division to be demonstrated to be within its limit in accordance with the SFCP. Protection System Response Time is a new definition added to Chapter 1 of the TS. This parameter measures the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component.

In addition, the following TS tables of response time limits are relocated to licensee control - Table 3.3.1.2, Table 3.3.2.3, Table 3.3.3.3, and Table 3.3.4.2.3.

The Chapter 1 Discussions of Change described the combination of the definitions of Reactor Protection System Response Time, Isolation System Response Time, and Emergency Core Cooling System (ECCS) Response Time into a new Plant Protection System Response Time definition which incorporates all aspects of the existing definitions. This combination of the existing LCO and surveillance requirements does not result in any technical changes. The current SRs 4.3.1.3, 4.3.2.3, 4.3.3.3 also contain statements regarding staggered testing of the channels per trip system. As discussed in Sections 3.2.13 and 3.5.14.1 of the PPS Licensing Technical Report, the PPS coincidence logic is changed from "one out of two taken twice" to "two out of four." As a result, the term "trip systems" is no longer applicable under the new design.

The remaining discussion of the staggering of tests is relocated to the SFCP, which is consistent with the BWR/4 Standard Technical Specifications (NUREG-1433).

The response time limits in current TS Tables 3.3.1.2, 3.3.2.3, and 3.3.3.3 are relocated to licensee control under the controls of 10 CFR 50.59. This change is consistent with the guidance in Generic Letter 93-08, "Relocation of Technical Specification Tables of Instrument Response Time Limits." The surveillances will continue to require the subject systems be operable with response times within limit. Relocating the tables of instrument response time limits from the TS to a document controlled under 10 CFR 50.59 will not alter these surveillance requirements. The plant procedures for response time testing include acceptance criteria that reflect the response time limits in the tables being relocated. The response time limits will be included in the TS Bases. This change is acceptable because the TS will continue to require verification that the response time limits are met and the limits are controlled under the appropriate regulatory process.

D03

The current TS contain four timer functions: TS Table 3.3.2-1, Function 4.h, "HPCI Steam Line Δ Press Timer," and Function 5.h, "RCIC Steam Line Δ Pressure Timer; TS Table 3.3.3-1, Function 4.c, "ADS Timer," and Function 4.h, "ADS Drywell Pressure Bypass Timer." These functions, as well as the associated Actions, trip setpoints, allowable values, and surveillances are removed from the TS.

These timers are implemented within the digital PPS. As discussed in Section 5.3.2 of the PPS Licensing Technical Report, constants, such as the values for these times, and the associated software routines are constantly monitored by the self-test system to ensure that the values and routines are not intentionally or inadvertently changed. The specific values and timer functions are being incorporated within the programing of the PPS logic and are no longer discreet components with timing adjustments that can be made through routine testing and calibration. As such, these devices are removed from the TS as discrete components and will be designed and tested as part of the overall digital system and will not require specific testing or calibration to maintain their design setting. This change is acceptable because it is not necessary for these timer values to be in the TS under the new design.

D04

Proposed TS 3.3.2 contains a new LCO that requires the PPS divisions to be operable and associated Actions to be followed if the PPS divisions are inoperable. All four PPS divisions are required to be operable in Operational Conditions 1, 2, 3, 4, and 5, reflecting the safety functions performed by the supported equipment. The Actions to follow if a PPS division is inoperable depend on the Operational Condition. The Actions also reflect that the PPS divisions perform two primary roles: reactor trip and non-reactor trip, and the appropriate compensatory measures are different for each role.

Action a applies if a division is inoperable in Operational Condition 1, 2, or 3. If one or more reactor trip divisions are inoperable, the associated reactor trip units must be placed in the trip condition within 6 hours, or the plant must be in Hot Shutdown within 12 hours and Cold Shutdown within 24 hours. The 6-hour time to place the channel in trip is acceptable given the redundancy and reliability of the PPS, and it provides time for maintenance. The times provided to shutdown the plant are consistent with similar TS Actions.

If one or more non-reactor trip divisions are inoperable in Operational Condition 1, 2, or 3, Action a requires the associated equipment (e.g., Emergency Core Cooling Systems, Reactor Core Isolation Cooling, Primary Containment isolation valves, etc.) to be declared inoperable within 6 hours, or the plant must be in Hot Shutdown within 12 hours and Cold Shutdown within 24 hours. The 6-hour time to declare the supported equipment inoperable is acceptable given the redundancy and reliability of the PPS, and it provides time for corrective maintenance. The times provided to shutdown the plant are consistent with similar TS Actions.

Action b applies in Operational Condition 4. If one or more reactor trip divisions are inoperable, then within 1 hour all insertable control rods must be verified to be inserted into the core and the Reactor Mode Switch must be locked in the Shutdown position. Control rods that have been removed under the allowances of Specification 3.9.10.1, "Control Rod Removal," or 3.9.10.2, "Multiple Control Removal," do not have to be verified to be inserted. The 1-hour time to take the required Actions are acceptable given the redundancy and reliability of the PPS, the time required to perform the action, and provides limited time to take corrective maintenance.

If one or more non-reactor trip divisions are inoperable in Operational Condition 4, Action b requires that within 1 hour any supported ECCS that is required to be operable by TS 3.5.2, "Reactor Pressure Vessel Water Inventory Control," must be declared inoperable and any supported penetration flow path(s) credited for automatic isolation in calculating Drain Time to be declared incapable of automatic isolation. These actions are acceptable because they ensure the safety functions required by Specification 3.5.2 are able to be performed.

Action c applies in Operational Condition 5. If one or more reactor trip divisions are inoperable, then within 1 hour all insertable control rods must be verified to be inserted into the core and all Core Alternations must be suspended. Control rods that have been removed under the allowances of Specification 3.9.10.1, or 3.9.10.2, "Multiple Control Rod Removal," do not have to be verified to be inserted. The one-hour time to take the required Actions are acceptable given the redundancy and reliability of the PPS, the time required to perform the action, and provides limited time to take corrective maintenance.

If one or more non-reactor trip divisions are inoperable in Operational Condition 5, Action c requires that within one hour, any supported ECCS that is required to be operable by TS 3.5.2, must be declared inoperable and any supported penetration flow path(s) credited for automatic isolation in calculating Drain Time to be declared incapable of automatic isolation. These actions are acceptable because they ensure the safety functions required by TS 3.5.2 can be performed. The change is acceptable because these actions reflect the impact of inoperable divisions in the associated operating conditions on TS systems required to be operable.

D05

A new surveillance is added to TS 3.3.2. Proposed SR 4.3.2.2 requires verification that each division provides a scram signal to the scram discharge volume drain and vent valves in accordance with the SFCP. TS 3.1.3.1, "Control Rods," SR 4.1.3.1.4 requires verification that the scram discharge volume drain and vent valves close within 30 seconds after receipt of a signal for control rods to scram. The proposed SR 4.3.2.2 verifies that the PPS provides this signal to the scram discharge volume drain and vent valves. This testing is currently performed under surveillances in the existing TS 3.3.1, but will be performed as a manual test, using the PPS divisions. This change is acceptable because the required testing continues to be performed under a new requirement.

Unit 1

Proposed Technical Specifications

CTS

3/4.3 INSTRUMENTATION

3/4.3.2 PLANT PROTECTION SYSTEM DIVISIONS

LIMITING CONDITION FOR OPERATION

3.3.2 The four Plant Protection System divisions shall be OPERABLE.

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

ACTION:

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

   1. With one or more reactor trip divisions inoperable, within 6 hours:
      a. Place the associated reactor trip units in the tripped condition, or
      b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.
   2. With one or more non-reactor trip divisions inoperable, within 6 hours:
      a. Declare the associated equipment inoperable, or
      b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

b. In OPERATIONAL CONDITION 4:
   1. With one or more reactor trip divisions inoperable , within 1 hour:
      a. Verify all insertable control rods are inserted in the core*, and,
      b. Lock the Reactor Mode Switch in the Shutdown position.
   2. With one or more non-reactor trip divisions inoperable, within 1 hour:
      a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
      b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

c. In OPERATIONAL CONDITION 5:
   1. With one or more reactor trip divisions inoperable, within 1 hour:
      a. Verify all insertable control rods are inserted in the core*, and
      b. Suspend all operations involving CORE ALTERATIONS.
   2. With one or more non-reactor trip divisions inoperable, within 1 hour:
      a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
      b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

SURVEILLANCE REQUIREMENTS

4.3.1.3
4.3.2.3
4.3.3.3

4.3.2.1 - The PLANT PROTECTION SYSTEM RESPONSE TIME of each division shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program.

4.3.2.2 - Verify that each Division provides a scram signal to all reactor trip components in accordance with the Surveillance Frequency Control Program.

Unit 2

Proposed Technical Specifications

3/4.3 INSTRUMENTATION

3/4.3.2 PLANT PROTECTION SYSTEM DIVISIONS

LIMITING CONDITION FOR OPERATION

3.3.2 The four Plant Protection System divisions shall be OPERABLE.

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

ACTION:

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

1. With one or more reactor trip divisions inoperable, within 6 hours:
   a. Place the associated reactor trip units in the tripped condition, or
   b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.
2. With one or more non-reactor trip divisions inoperable, within 6 hours:
   a. Declare the associated equipment inoperable, or
   b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

b. In OPERATIONAL CONDITION 4:

1. With one or more reactor trip divisions inoperable , within 1 hour:
   a. Verify all insertable control rods are inserted in the core*, and,
   b. Lock the Reactor Mode Switch in the Shutdown position.
2. With one or more non-reactor trip divisions inoperable, within 1 hour:
   a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
   b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

c. In OPERATIONAL CONDITION 5:

1. With one or more reactor trip divisions inoperable, within 1 hour:
   a. Verify all insertable control rods are inserted in the core*, and
   b. Suspend all operations involving CORE ALTERATIONS.
2. With one or more non-reactor trip divisions inoperable, within 1 hour:
   a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
   b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

SURVEILLANCE REQUIREMENTS

4.3.2.1 - The PLANT PROTECTION SYSTEM RESPONSE TIME of each division shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program.

4.3.2.2 - Verify that each Division provides a scram signal to all reactor trip components in accordance with the Surveillance Frequency Control Program.

Unit 1

Revised Technical Specifications Bases (For Information Only)

3/4.3.3 EMERGENCY CORE COOLING ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

3.3.1 Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

TS Bases 3/4.3.2
Insert 1

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3.A REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

3.3.3 Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close

3.3.2 PLANT PROTECTION SYSTEM DIVISIONS

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its division level actuations (i.e. system level actuations for RPS, NSSSS, and ECCS) under out of service conditions that exceed the capabilities of division external and internal redundancies. The single failure of a redundant module or communication component does not constitute entry into this specification.

The reactor trip function automatically initiates a reactor scram to:

Preserve the integrity of the fuel cladding
Preserve the integrity of the reactor coolant system
Minimize the energy which must be adsorbed following a loss-of-coolant accident
Prevent inadvertent criticality.

The reactor scram logic and actuation is processed by 2 PPS logic.

The primary containment function ensure that the release of radioactive materials form the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analysis. The emergency core cooling function is provided to initiate actions to mitigate the consequence of accidents that are beyond the ability of the operator to control. NSSSS and ECCS logic is processed by Level 2 PPS logic, and is fanned out by Level 3 logic.

A summary PPS overview diagram and discussion is provided preceding the Bases documentation for Specification 3.3.1 that details the relationship between channel and division, as well as providing functional description of each logic level. The divisional components and architecture are described below.

Local Coincidence Logic (LCL) architecture

There is one Coincident Logic Cabinet (CLC) per division. The CLC contains the AC160 process control system hardware with the following configurations:

- Two redundant Safety AC and safety DC cabinet power supplies
- Two redundant and diverse internal DC power supplies
- Four PM646A Processor Modules running the LCL application
    - Two redundant processors for RPS
    - Two redundant processors for ECCS and NSSSS
- Three CI631 AF100 Communication Modules
- Three DI6212 Digital Input Modules for SD system level manual actuation confirmatory switches and inputs from the BPL for fast reactor trip functions (see detailed channel descriptions in 3.3.1)
- Four DO620 Digital Output Modules for interfacing to the RPS Termination Unit (RPS TU)

Reactor Scram Matrix and RPS Trip Unit

Within each division is a Reactor Scram Matrix that is part of the RPS TU. The LCL in each division performs 2 out of 4 coincidence logic on RPS trip functions received from the BPL vi the RPS PM646A modules. Once a trip function passes coincidence logic, the RPS PM646A deenergize two redundant DO module channels that interface with the RPS Scram Matrix. The RPS Scram Matrix is arrange such that at least one DO channel from each RPS PM646A processor module needs to deenergize to actuate the Reactor Scram Matrix in that division.

The RPS Scram Matrix is also connected to the Window Watchdog Timer (WWDT) relay of each RPS PM646A. If both processor modules fail, a WWDT scram will be issued.

When the Scram Matrix logic is satisfied, the RPS TU solid state relays are deenergized. The Division 1 and 3 RPS TUs are logically ORed such that if a solid state relay is deenergized in either division, the power will be removed from the ‘A’ Scram Solenoid Pilot Valves (SSPVs). Similarly, the Division 2 and 4 RPS TUs are logically ORed such that if a solid state relay is deenergized in either division, the power will be removed from the ‘B’ SSPVs. Either case, whether actuated automatically or by way of manual scram pushbuttons in the MCR, results in a half scram. When both occur with overlap in time, a full scram is actuated.

Typically, scram inputs are subjected to 2 out of 4 logic as part of the LCL application. However, Specification 3.3.1 Functions 1 and 2 are exceptions, details are provided in their respective detailed function discussion.

Integrated Logic Processor (ILP)

Each division contains a number of ILP cabinets that correlates to the amount of equipment actuated.

Division 1: 6 cabinets
Division 2: 5 cabinets
Division 3: 2 cabinets
Division 4: 2 cabinets

Each ILP cabinet contains the AC160 process control system hardware with the following configurations:

- Two redundant PM646A Processor Modules running the ILP application which perform component fanout actuation commands for ECCS and NSSSS system level actuations
- Three CI631 AF100 Communication Modules
- Many DO620 Digital Output Modules for actuating components that do not require a CIM
- Many DI621 Digital Input Modules for display inputs, component feedback signals, and various equipment protection instruments
- One AI688 analog input module for display inputs and various equipment protection instruments

Due to the termination location of a variety of sensors within the Auxiliary Equipment Room, those signals are terminated in the ILP cabinet. The ILP performs bistable and coincidence functions as required based on the type and importance of signal. The majority of these inputs are asset protection in nature.

The ILP in each division of PPS receive system level NSSSS and ECCS actuation commands via the HSLs from the LCL in its division. Those commands are processed redundantly and communicated to the CIM via the Safety Remote Node Controller (SRNC). The SRNC performs 2 out of 2 verification checks on the requested command signal to prevent spurious actuation.

ACTIONS

PPS divisions are required to be operable in all OPCONs. Divisional inoperability has a broad spectrum of potential effects. For example, while there is only one CLC per division, the number of ILP cabinets changes depending on which division is of interest.

The Actions for specification 3.3.2 reflect the need to declare supported mechanical equipment inoperable for the purposes of automatic safety actuations when a division level fault is realized. These actions are OPCON specific and avoid creating differing allowable out of service times and/or action steps by yielding to the allowable out of service times of the affected systems and functions as opposed to attempting to predict all possible failures within Technical Specifications.

To that end, procedure <u>GP-XX [TBD after vender manual and FMEA delivery and acceptance]</u> has been created. This procedure provides a logical and methodical means to determine the scope of affected equipment for any failure without presuming a failure type or mode.

These actions reflect the dedicated redundant processing and communications capabilities for both the reactor trip function, and the ECCS / NSSSS functions. The phrase non-reactor trip divisions is used specifically to ensure there are no potential gaps in specification coverage. For all tech spec divisional function failures, the affected components and functions are either part of the dedicated reactor trip processing and communications, or part of the dedicated non-reactor trip processing and communications.

Manual component operation via the SDs uses the AF100 network, which is separate from the processing and communication equipment used for automatic safety actuations.

SURVEILLANCES

PLANT PROTECTION SYSTEM RESPONSE TIME is performed in accordance with Surveillance Requirement 4.3.2.1

> The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each division is completed within the time limit assumed in the safety analyses.

Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

Response time testing for sensors are not required based on the analysis in NEDO 32291-A. Response time testing of the remaining channel components is required as noted in Table B3.3.2-1.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

A functional check of each Divisions capability to actuate all scram components, including the WWDT relays, is performed in accordance with Surveillance Requirement 4.3.2.2

Digital outputs can be monitored by application diagnostics with the ITP that compares the LCL trip signal to the feedback signals received from actuated components. There is no effective automatic diagnostic that detects an error in the DO modules communicating reactor trip status to the RPS TU. Further, the operability of the PM646A WWDT relay connection to the RPS Scram Matrix is not testable within the automatic diagnostics.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

> The opening of a containment isolation valve that was locked or sealed closed to satisfy Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Self testing of the PPS connections includes ILP X1 and X2 outputs through the SRNC and ends at the CIM input terminals. Therefore, surveillance of the CIM and its associated connection to its associated component can be accomplished by any provided means (i.e. SDs, Ovation, DCS, or manual local open and closed command) to satisfy Surveillance Requirements 4.0.5 and 4.6.3.2 as applicable.

TABLE B 3.3.2-1
PLANT PROTECTION SYSTEM DIVISIONS
RESPONSE TIMES

TABLE 3.3.1-1 FUNCTION	RESPONSE TIME (Seconds)
2. Average Power Range Monitor	
e. 2-Out-Of-4 Voter	≤0.05(a)
3. Reactor Vessel Steam Dome Pressure – High	≤0.55
6. Reactor Vessel Water Level	
a. Low, Low, Low Level 1	<1.0(d)(e)
c. Low - Level 3	≤1.05(c)
20. Turbine Stop Valve - Closure	
a. Reactor Trip	≤0.06
21. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	
a. Reactor Trip	≤0.08(b)
19. Main Steam Line Isolation Valve - Closure	≤0.06
22. Main Steam Line Pressure - Low	≤1.0(d)(e)
23. Main Steam Line Flow - High	≤1.0(d)(e)

ECCS FUNCTION	
Core Spray System	≤27#
Low Pressure Coolant Injection Mode of RHR System	≤40#
High Pressure Coolant Injection System	≤60#

TABLE B 3.3.2-1
PLANT PROTECTION SYSTEM DIVISIONS
TABLE NOTATIONS

ECCS actuation instrumentation is eliminated from response time testing.

(a) Neutron detectors, APRM channel and 2-Out-Of-4 Voter channel digital electronics are exempt from response time testing. Response time shall be measured from activation of the 2-Out-Of-4 Voter output relay. For applications of Specification 4.3.2.1, the redundant outputs from each 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8. Testing of OPRM and APRM outputs shall alternate.

(b) Measured from start of turbine control valve fast closure.

(c) Sensor is eliminated from response time testing for the reactor trip function. PLANT PROTECTION SYSTEM RESPONSE TIME and conformance to the administrative limits for the remaining channel is required.

(d) Isolation system instrumentation response time for MSIV only. No diesel generator delays assumed for MSIVs.

(e) Sensor channel is eliminated from response time testing for MSIV isolation. PLANT PROTECTION SYSTEMRESPONSE TIME and conformance to the administrative limits for the remaining channel is required.

Unit 2

Revised Technical Specifications Bases (For Information Only)

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

3/4.3.1

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

TS Bases
3/4.3.2
Insert 1

3/4.3.3.A REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

3/4.3.3

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation

3.3.2 PLANT PROTECTION SYSTEM DIVISIONS

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its division level actuations (i.e. system level actuations for RPS, NSSSS, and ECCS) under out of service conditions that exceed the capabilities of division external and internal redundancies. The single failure of a redundant module or communication component does not constitute entry into this specification.

The reactor trip function automatically initiates a reactor scram to:

Preserve the integrity of the fuel cladding
Preserve the integrity of the reactor coolant system
Minimize the energy which must be adsorbed following a loss-of-coolant accident
Prevent inadvertent criticality.

The reactor scram logic and actuation is processed by 2 PPS logic.

The primary containment function ensure that the release of radioactive materials form the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analysis. The emergency core cooling function is provided to initiate actions to mitigate the consequence of accidents that are beyond the ability of the operator to control. NSSSS and ECCS logic is processed by Level 2 PPS logic, and is fanned out by Level 3 logic.

A summary PPS overview diagram and discussion is provided preceding the Bases documentation for Specification 3.3.1 that details the relationship between channel and division, as well as providing functional description of each logic level. The divisional components and architecture are described below.

Local Coincidence Logic (LCL) architecture

There is one Coincident Logic Cabinet (CLC) per division. The CLC contains the AC160 process control system hardware with the following configurations:

- Two redundant Safety AC and safety DC cabinet power supplies
- Two redundant and diverse internal DC power supplies
- Four PM646A Processor Modules running the LCL application
    - Two redundant processors for RPS
    - Two redundant processors for ECCS and NSSSS
- Three CI631 AF100 Communication Modules
- Three DI6212 Digital Input Modules for SD system level manual actuation confirmatory switches and inputs from the BPL for fast reactor trip functions (see detailed channel descriptions in 3.3.1)
- Four DO620 Digital Output Modules for interfacing to the RPS Termination Unit (RPS TU)

Reactor Scram Matrix and RPS Trip Unit

Within each division is a Reactor Scram Matrix that is part of the RPS TU. The LCL in each division performs 2 out of 4 coincidence logic on RPS trip functions received from the BPL vi the RPS PM646A modules. Once a trip function passes coincidence logic, the RPS PM646A deenergize two redundant DO module channels that interface with the RPS Scram Matrix. The RPS Scram Matrix is arrange such that at least one DO channel from each RPS PM646A processor module needs to deenergize to actuate the Reactor Scram Matrix in that division.

The RPS Scram Matrix is also connected to the Window Watchdog Timer (WWDT) relay of each RPS PM646A. If both processor modules fail, a WWDT scram will be issued.

When the Scram Matrix logic is satisfied, the RPS TU solid state relays are deenergized. The Division 1 and 3 RPS TUs are logically ORed such that if a solid state relay is deenergized in either division, the power will be removed from the ‘A’ Scram Solenoid Pilot Valves (SSPVs). Similarly, the Division 2 and 4 RPS TUs are logically ORed such that if a solid state relay is deenergized in either division, the power will be removed from the ‘B’ SSPVs. Either case, whether actuated automatically or by way of manual scram pushbuttons in the MCR, results in a half scram. When both occur with overlap in time, a full scram is actuated.

Typically, scram inputs are subjected to 2 out of 4 logic as part of the LCL application. However, Specification 3.3.1 Functions 1 and 2 are exceptions, details are provided in their respective detailed function discussion.

Integrated Logic Processor (ILP)

Each division contains a number of ILP cabinets that correlates to the amount of equipment actuated.

Division 1: 6 cabinets
Division 2: 5 cabinets
Division 3: 2 cabinets
Division 4: 2 cabinets

Each ILP cabinet contains the AC160 process control system hardware with the following configurations:

- Two redundant PM646A Processor Modules running the ILP application which perform component fanout actuation commands for ECCS and NSSSS system level actuations
- Three CI631 AF100 Communication Modules
- Many DO620 Digital Output Modules for actuating components that do not require a CIM
- Many DI621 Digital Input Modules for display inputs, component feedback signals, and various equipment protection instruments
- One AI688 analog input module for display inputs and various equipment protection instruments

Due to the termination location of a variety of sensors within the Auxiliary Equipment Room, those signals are terminated in the ILP cabinet. The ILP performs bistable and coincidence functions as required based on the type and importance of signal. The majority of these inputs are asset protection in nature.

The ILP in each division of PPS receive system level NSSSS and ECCS actuation commands via the HSLs from the LCL in its division. Those commands are processed redundantly and communicated to the CIM via the Safety Remote Node Controller (SRNC). The SRNC performs 2 out of 2 verification checks on the requested command signal to prevent spurious actuation.

ACTIONS

PPS divisions are required to be operable in all OPCONs. Divisional inoperability has a broad spectrum of potential effects. For example, while there is only one CLC per division, the number of ILP cabinets changes depending on which division is of interest.

The Actions for specification 3.3.2 reflect the need to declare supported mechanical equipment inoperable for the purposes of automatic safety actuations when a division level fault is realized. These actions are OPCON specific and avoid creating differing allowable out of service times and/or action steps by yielding to the allowable out of service times of the affected systems and functions as opposed to attempting to predict all possible failures within Technical Specifications.

To that end, procedure <u>GP-XX [TBD after vender manual and FMEA delivery and acceptance]</u> has been created. This procedure provides a logical and methodical means to determine the scope of affected equipment for any failure without presuming a failure type or mode.

These actions reflect the dedicated redundant processing and communications capabilities for both the reactor trip function, and the ECCS / NSSSS functions. The phrase non-reactor trip divisions is used specifically to ensure there are no potential gaps in specification coverage. For all tech spec divisional function failures, the affected components and functions are either part of the dedicated reactor trip processing and communications, or part of the dedicated non-reactor trip processing and communications.

Manual component operation via the SDs uses the AF100 network, which is separate from the processing and communication equipment used for automatic safety actuations.

SURVEILLANCES

PLANT PROTECTION SYSTEM RESPONSE TIME is performed in accordance with Surveillance Requirement 4.3.2.1

> The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each division is completed within the time limit assumed in the safety analyses.

Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

Response time testing for sensors are not required based on the analysis in NEDO 32291-A. Response time testing of the remaining channel components is required as noted in Table B3.3.2-1.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

A functional check of each Divisions capability to actuate all scram components, including the WWDT relays, is performed in accordance with Surveillance Requirement 4.3.2.2

Digital outputs can be monitored by application diagnostics with the ITP that compares the LCL trip signal to the feedback signals received from actuated components. There is no effective automatic diagnostic that detects an error in the DO modules communicating reactor trip status to the RPS TU. Further, the operability of the PM646A WWDT relay connection to the RPS Scram Matrix is not testable within the automatic diagnostics.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

> The opening of a containment isolation valve that was locked or sealed closed to satisfy Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Self testing of the PPS connections includes ILP X1 and X2 outputs through the SRNC and ends at the CIM input terminals. Therefore, surveillance of the CIM and its associated connection to its associated component can be accomplished by any provided means (i.e. SDs, Ovation, DCS, or manual local open and closed command) to satisfy Surveillance Requirements 4.0.5 and 4.6.3.2 as applicable.

TABLE B 3.3.2-1
PLANT PROTECTION SYSTEM DIVISIONS
RESPONSE TIMES

TABLE 3.3.1-1 FUNCTION	RESPONSE TIME (Seconds)
2. Average Power Range Monitor	
e. 2-Out-Of-4 Voter	≤0.05(a)
3. Reactor Vessel Steam Dome Pressure – High	≤0.55
6. Reactor Vessel Water Level	
a. Low, Low, Low Level 1	<1.0(d)(e)
c. Low - Level 3	≤1.05(c)
20. Turbine Stop Valve - Closure	
a. Reactor Trip	≤0.06
21. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	
a. Reactor Trip	≤0.08(b)
19. Main Steam Line Isolation Valve - Closure	≤0.06
22. Main Steam Line Pressure - Low	≤1.0(d)(e)
23. Main Steam Line Flow - High	≤1.0(d)(e)
ECCS FUNCTION	
Core Spray System	≤27#
Low Pressure Coolant Injection Mode of RHR System	≤40#
High Pressure Coolant Injection System	≤60#

TABLE B 3.3.2-1
PLANT PROTECTION SYSTEM DIVISIONS
TABLE NOTATIONS

ECCS actuation instrumentation is eliminated from response time testing.

(a) Neutron detectors, APRM channel and 2-Out-Of-4 Voter channel digital electronics are exempt from response time testing. Response time shall be measured from activation of the 2-Out-Of-4 Voter output relay. For applications of Specification 4.3.2.1, the redundant outputs from each 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8. Testing of OPRM and APRM outputs shall alternate.

(b) Measured from start of turbine control valve fast closure.

(c) Sensor is eliminated from response time testing for the reactor trip function. PLANT PROTECTION SYSTEM RESPONSE TIME and conformance to the administrative limits for the remaining channel is required.

(d) Isolation system instrumentation response time for MSIV only. No diesel generator delays assumed for MSIVs.

(e) Sensor channel is eliminated from response time testing for MSIV isolation. PLANT PROTECTION SYSTEMRESPONSE TIME and conformance to the administrative limits for the remaining channel is required.

Specification 3/4.3.3, Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation

Unit 1

Current Technical Specifications Markup

INSTRUMENTATION

3/4.3.3~~.A~~ REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION D01

LIMITING CONDITION FOR OPERATION

3.3.3~~.A~~ The RPV Water Inventory Control (WIC) instrumentation channels shown in Table 3.3.3~~.A~~-1 shall be OPERABLE. D01

APPLICABILITY: As shown in Table 3.3.3~~.A~~-1

ACTION:

required

a. With one or more required channels inoperable ~~in a trip system~~, take the ACTION referenced in Table 3.3.3~~.A~~-1 ~~for the trip system~~. D03 D01

SURVEILLANCE REQUIREMENTS

~~4.3.3.1.A Each RPV Water Inventory Control (WIC) instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL FUNCTIONAL TEST as shown in Table 4.3.3.A-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.3.A-1.~~ D04

None

D01

TABLE 3.3.3~~.A~~-1

~~RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION~~

D03

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS ~~PER TRIP FUNCTION~~	APPLICABLE OPERATIONAL CONDITIONS	ACTION
~~1.~~ ~~DELETED~~			
~~2.~~ ~~DELETED~~			
1 ~~3.~~ RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION			
a. Reactor Vessel Water Level - Narrow Range, Low - Level 3	3 ~~2 in one trip system~~	a (~~b~~)	20 ~~38~~
2 ~~4.~~ REACTOR WATER CLEANUP SYSTEM ISOLATION			
a. Reactor Vessel Water Level - Wide Range, Low, Low - Level 2	3 ~~2 in one trip system~~	a (~~b~~)	20 ~~38~~

D05

D05 D03

D05 D03

D06

~~(a) DELETED~~

a (~~b~~) When automatic isolation of the associated penetration flow path(s) is credited in calculating DRAIN TIME.

D05

~~(c) DELETED~~

PTS

D01

TABLE 3.3.3~~.A~~-1 (Continued)
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION
ACTION STATEMENTS

Action 20

ACTION ~~38~~ 20 - Immediately initiate action to place the channel in trip, or declare the ~~associated trip system for the~~ penetration flow path(s) incapable of automatic isolation and initiate action to calculate DRAIN TIME. D03

~~ACTION 39 - DELETED~~

D05

~~ACTION 40 - DELETED~~

D01

D02

TABLE 3.3.3.~~A~~-2

RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION ~~SETPOINTS~~ ALLOWABLE VALUES

TRIP FUNCTION	ALLOWABLE VALUE	
~~1.~~ ~~DELETED~~		
~~2.~~ ~~DELETED~~		D05
1 ~~3~~. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		D05
a. Reactor Vessel Water Level - Narrow Range Low - Level 3	≥ 11.0 inches	D06
2 ~~4~~. REACTOR WATER CLEANUP SYSTEM ISOLATION		
a. Reactor Vessel Water Level - Wide Range Low, Low - Level 2	≥ -45 inches	D06 D05

~~TABLE 4.3.3.A-1~~
~~RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

~~TRIP FUNCTION~~	~~CHANNEL CHECK(a)~~	~~CHANNEL FUNCTIONAL TEST(a)~~	~~LOGIC SYSTEM FUNCTIONAL TEST(a)~~	~~OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED~~
~~1. DELETED~~				
~~2. DELETED~~				
~~3. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION~~				
~~a. Reactor Vessel Water Level - Low - Level 3~~			~~N.A.~~	~~(b)~~
~~4. REACTOR WATER CLEANUP SYSTEM ISOLATION~~				
~~a. Reactor Vessel Water Level - Low, Low - Level 2~~			~~N.A.~~	~~(b)~~

~~(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.~~
~~(b) When automatic isolation of the associated penetration flow path(s) is credited in calculating DRAIN TIME.~~

D04

Unit 2

Current Technical Specifications Markup

INSTRUMENTATION

3/4.3.3~~.A~~ REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION D01

LIMITING CONDITION FOR OPERATION

3.3.3~~.A~~ The RPV Water Inventory Control (WIC) instrumentation channels shown in Table 3.3.3~~.A~~-1 shall be OPERABLE. D01

APPLICABILITY: As shown in Table 3.3.3~~.A~~-1

ACTION:

required

a. With one or more required channels inoperable ~~in a trip system~~, take the ACTION referenced in Table 3.3.3~~.A~~-1 ~~for the trip system~~. D03 D01

SURVEILLANCE REQUIREMENTS

~~4.3.3.1.A Each RPV Water Inventory Control (WIC) instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL FUNCTIONAL TEST as shown in Table 4.3.3.A-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.3.A-1.~~ D04

None

TABLE 3.3.3~~.A~~-1 D01

~~RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION~~

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS ~~PER TRIP FUNCTION~~	APPLICABLE OPERATIONAL CONDITIONS	ACTION	
~~1.~~ ~~DELETED~~				
~~2.~~ ~~DELETED~~				D05
1 ~~3~~. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level - Narrow Range, Low - Level 3	3 ~~2 in one trip system~~	(~~b~~ a)	20 ~~38~~	D05 D03
2 ~~4~~. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. Reactor Vessel Water Level - Wide Range, Low, Low - Level 2	3 ~~2 in one trip system~~	(~~b~~ a)	20 ~~38~~	D05 D03 D06

~~(a) DELETED~~

a (~~b~~) When automatic isolation of the associated penetration flow path(s) is credited in calculating DRAIN TIME. D05

~~(c) DELETED~~

PTS

D01

TABLE 3.3.3~~.A~~-1 (Continued)
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION
ACTION STATEMENTS

20

Action 20

ACTION ~~38~~ - Immediately initiate action to place the channel in trip, or declare the ~~associated trip system for the~~ penetration flow path(s) incapable of automatic isolation and initiate action to calculate DRAIN TIME.

D03

~~ACTION 39 -~~ ~~DELETED~~

D05

~~ACTION 40 -~~ ~~DELETED~~

D01

D02

TABLE 3.3.3~~.A~~-2

RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION ~~SETPOINTS~~ ALLOWABLE VALUES

TRIP FUNCTION	ALLOWABLE VALUE
~~1.~~ ~~DELETED~~	
D05	
~~2.~~ ~~DELETED~~	
1 ~~3.~~ RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	D05
a. Reactor Vessel Water Level - Narrow Range, Low - Level 3	≥ 11.0 inches D06
2 ~~4.~~ REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. Reactor Vessel Water Level - Wide Range, Low, Low - Level 2	≥ -45 inches D05 D06

~~TABLE 4.3.3.A-1~~

~~RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

~~TRIP FUNCTION~~	~~CHANNEL CHECK(a)~~	~~CHANNEL FUNCTIONAL TEST(a)~~	~~LOGIC SYSTEM FUNCTIONAL TEST(a)~~	~~OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED~~
~~1. DELETED~~				
~~2. DELETED~~				
~~3. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION~~				
~~a. Reactor Vessel Water Level - Low - Level 3~~			~~N.A.~~	~~(b)~~
~~4. REACTOR WATER CLEANUP SYSTEM ISOLATION~~				
~~a. Reactor Vessel Water Level - Low, Low - Level 2~~			~~N.A.~~	~~(b)~~

D04

~~(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.~~
~~(b) When automatic isolation of the associated penetration flow path(s) is credited in calculating DRAIN TIME.~~

Discussion of Changes

Discussion of Changes

Technical Specification 3/4.3.3
Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation

D01
Current TS 3.3.3.A, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation," is relabeled to Specification 3.3.3 due to changes to other specifications. As a result, SR 4.3.3.1.A is relabeled Surveillance 4.3.3.1, Table 3.3.3.A-1 is relabeled Table 3.3.3-1, and Table 3.3.3.A-2 is relabeled Table 3.3.3-2. The proposed changes are acceptable because the relabeling of the existing requirements does not result in any technical changes to the requirements.

D02
Current TS 3.3.3.A, Table 3.3.3.A-2 (relabeled Table 3.3.3-2) is renamed from "RPV Water Inventory Control (WIC) Instrumentation Setpoints," to "RPV Water Inventory Control (WIC) Instrumentation Allowable Values." The proposed change is acceptable because the existing table only contains Allowable Values and not setpoints. The change is an editorial improvement which does not result in any technical changes to the requirements.

D03
Current TS 3.3.3.A, Table 3.3.3.A-1 (relabeled Table 3.3.3-1) contains a column labeled, "Minimum Operable Channels per Trip System." For the two functions in the Table, the entries are "2 in one trip system." Table 3.3.3.A-1, Action 38, and Action a. both refer to trip systems. In the proposed TS, the column is relabeled "Minimum Operable Channels," and the entries for both functions are changed to "3". Both Action a and Action 38 (renamed Action 20) are revised to eliminate references to trip systems.

As discussed in Sections 5.2.2.3 and 5.2.2.5, respectively, of the LGS PPS SyRS (i.e., Attachment 7 to this LAR), the instrumentation logic in Table 3.3.3.A-1 for Function 3.a, "RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level - Low - Level 3," and Function 4.a, "Reactor Water Cleanup System Isolation, Reactor Vessel Water Level - Low - Level 2," is changed from "one out of two taken twice" to "two out of four." Any two channels exceeding the setpoint will result in isolation of the subject system and "trip systems" is no longer applicable under the new design. As discussed in Section 3.2 of the PPS Licensing Technical Report, under the revised design, any three channels provide the required independence and redundancy. Therefore, the Minimum Operable Channels is changed to three.

In the proposed change, the Actions are revised to no longer refer to trip systems. Under the existing design and the "one out of two taken twice" isolation logic, one inoperable channel could result in the inability to automatically isolate the subject system. However, under the new design and the minimum requirement for three operable channels, placing one inoperable channel in trip will continue to provide the required automatic isolation. If more than one channel is inoperable and placed in trip the system will automatically isolate, or in lieu of tripping more than one channel, the Drain Time can be recalculated not assuming automatic isolation for the affected system.

The proposed change is acceptable because it reflects the new design of the affected functions and ensures that systems assumed to automatically isolate on low RPV water level in the Drain Time calculation will do so, or the Drain Time is determined not assuming automatic isolation.

D04

Current TS 3.3.3.A, SR 4.3.3.1.A, and Table 4.3.3.A-1 require a Channel Check and a Channel Functional Test be performed for the two instrumentation functions at a frequency specified in the SFCP when automatic isolation of the associated penetration flow path(s) is credited in calculating Drain Time.

In the proposed change, Table 4.3.3.1.A and SR 4.3.3.1.A are deleted. As described in the PPS Licensing Technical Report, the PPS performs a nearly continuous comparison equivalent to the Channel Check. Therefore, a manual Channel Check is not required. The digital platform also performs frequent self-diagnostics equivalent to the Channel Functional Test. Therefore, a manual Channel Functional Test is not required. As a result, the SRs in proposed TS 3.3.3 are removed. It should be noted, however, that Table 4.3.3.1.A Function, 3.a, "Reactor Vessel Water Level - Low -Level 3," and Function 4.a, "Reactor Vessel Water Level - Low, Low - Level 2," are also tested by proposed Specification 3.3.1.

The proposed change is acceptable because the automated testing of the two functions satisfies the requirements of 10 CFR 50.36(c)(3). The automatic testing of the digital platform will assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

D05

As an editorial improvement, items listed as deleted are removed and, where applicable, subsequent items are renumbered.

D06

Current TS 3.3.3.A, Table 3.3.3.A-1 and Table 3.3.3.A-2 contain two functions, Function 3.a, "Reactor Vessel, Water Level - Low, Level 3," and Function 4.a "Reactor Vessel, Water Level - Low Low, Level 2." These functions are renamed to be consistent with the function nomenclature used in proposed TS 3.3.1.

Function 3.a (Function 1.a in the proposed TS), "Reactor Vessel, Water Level - Low, Level 3," is renamed "Reactor Vessel, Water Level Narrow Range - Low, Level 3." Function 4.a (Function 2.a in the proposed TS), "Reactor Vessel, Water Level - Low Low, Level 2," is renamed "Reactor Vessel, Water Level Wide Range - Low Low, Level 2." The proposed change is acceptable because is maintains consistency within the TS without introducing any technical changes.

Unit 1

Proposed Technical Specifications

INSTRUMENTATION

3/4.3.3 REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The RPV Water Inventory Control (WIC) instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.3-1

ACTION:

a. With one or more required channels inoperable, take the ACTION referenced in Table 3.3.3-1.

SURVEILLANCE REQUIREMENTS

None.

TABLE 3.3.3-1
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

CTS

	TRIP FUNCTION	MINIMUM OPERABLE CHANNELS	APPLICABLE OPERATIONAL CONDITIONS	ACTION
Function 3 Function 4	1. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION			
	a. Reactor Vessel Water Level - Narrow Range, Low - Level 3	3	(a)	20
	2. REACTOR WATER CLEANUP SYSTEM ISOLATION			
	a. Reactor Vessel Water Level - Wide Range Low, Low - Level 2	3	(a)	20

(b) (a) When automatic isolation of the associated penetration flow path(s) is credited in calculating DRAIN TIME.

CTS

TABLE 3.3.3-1 (Continued)
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION
ACTION STATEMENTS

Action 38	ACTION 20 -	Immediately initiate action to place the channel in trip, or declare the associated penetration flow path(s) incapable of automatic isolation and initiate action to calculate DRAIN TIME.

CTS

TABLE 3.3.3-2
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION ALLOWABLE VALUES

CTS	TRIP FUNCTION	ALLOWABLE VALUE
Function 3	1. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
Function 4	a. Reactor Vessel Water Level - Narrow Range, Low - Level 3	≥ 11.0 inches
	2. REACTOR WATER CLEANUP SYSTEM ISOLATION	
	a. Reactor Vessel Water Level - Wide Range, Low, Low - Level 2	≥ -45 inches

Unit 2

Proposed Technical Specifications

INSTRUMENTATION

3/4.3.3 REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The RPV Water Inventory Control (WIC) instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.3-1

ACTION:

a. With one or more required channels inoperable, take the ACTION referenced in Table 3.3.3-1.

SURVEILLANCE REQUIREMENTS

None.

TABLE 3.3.3-1
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION			
a. Reactor Vessel Water Level - Narrow Range, Low - Level 3	3	(a)	20
2. REACTOR WATER CLEANUP SYSTEM ISOLATION			
a. Reactor Vessel Water Level - Wide Range Low, Low - Level 2	3	(a)	20

(a) When automatic isolation of the associated penetration flow path(s) is credited in calculating DRAIN TIME.

TABLE 3.3.3-1 (Continued)
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION
ACTION STATEMENTS

ACTION 20 - Immediately initiate action to place the channel in trip, or declare the associated penetration flow path(s) incapable of automatic isolation and initiate action to calculate DRAIN TIME.

TABLE 3.3.3-2
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION ALLOWABLE VALUES

TRIP FUNCTION	ALLOWABLE VALUE
1. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
a. Reactor Vessel Water Level - Narrow Range, Low - Level 3	≥ 11.0 inches
2. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. Reactor Vessel Water Level - Wide Range, Low, Low - Level 2	≥ -45 inches

Unit 1

Revised Technical Specifications Bases (For Information Only)

3/4.3.3 EMERGENCY CORE COOLING ACTUATION INSTRUMENTATION (Continued)

3.3.1 Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

TS Bases 3/4.3.3 Insert 1

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3.~~A~~ REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

~~The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.~~

~~Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."~~

~~With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close~~

3/4.3.3 REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, “Reactor Pressure Vessel (RPV) Water Inventory Control (WIC),” and the definition of DRAIN TIME. There are functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure. It is assumed, based on engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function-by-Function basis.

RHR System Isolation – Reactor Vessel Water Level Low - Level 3

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level Low - Narrow Range Level 3

Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level Low - Narrow Range Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level Low - Narrow Range Level 3 Function are available, only three channels are required to be OPERABLE.

The Reactor Vessel Water Level Low - Narrow Range Level 3 Allowable Value was chosen to be the same as the Plant Protection System Instrumentation Channel Reactor Vessel Water Level Low - Narrow Range Level 3 Allowable Value (Table 3.3.1-1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level Low - Narrow Range Level 3 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 2 valves.

<u>Reactor Water Cleanup (RWCU) System Isolation – Reactor Vessel Water Level – Wide Range Low, Low - Level 2</u>

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level – Wide Range Low, Low - Level 2Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System. Reactor Vessel Water Level – Wide Range Low, Low - Level 2signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level - Low, Low - Level 2 Function are available, only three channels are required to be OPERABLE.

The Reactor Vessel Water Level – Wide Range Low, Low - Level 2 Allowable Value was chosen to be the same as the Plant Protection System Instrument Channels Reactor Vessel Water Level – Low, Low Level 2 Allowable Value (Table 3.3.1-1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level – Low, Low Level 2 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 3 valves.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Actions

A note has been provided to modify the ACTIONs related to RPV Water Inventory Control instrumentation channels. The ACTIONs for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for each inoperable RPV Water Inventory Control instrumentation channel.

ACTION a. directs taking the appropriate ACTION referenced in Table 3.3.3.A-1. The applicable ACTION referenced in the table is Function dependent.

RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level Low - Level 3, and Reactor Water Cleanup System Isolation, Reactor Vessel Water Level – Wide Range Low, Low - Level 2functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. If the required instrumentation is inoperable, ACTION 20 directs immediate action to place the channel in trip. With the inoperable channel in the tripped condition, the remaining channels will isolate the penetration flow path on low water level. If two or more channels are inoperable and placed in trip, the penetration flow path will be isolated. Alternatively, ACTION 20 requires the associated penetration flow path(s) to be immediately declared incapable of automatic isolation and directs initiating action to calculate of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

3/4.3.3~~.A~~ RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, “Reactor Pressure Vessel (RPV) Water Inventory Control (WIC),” and the definition of DRAIN TIME. There are functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure. It is assumed, based on engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function-by-Function basis.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC)," and the definition of DRAIN TIME. There are functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure. It is assumed, based on engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function-by-Function basis.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

RHR System Isolation – Reactor Vessel Water Level Low - Level 3

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level Low - Level 3 Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level Low - Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level Low - Level 3 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level Low - Level 3 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level Low - Level 3 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level Low - Level 3 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 2 valves.

Reactor Water Cleanup (RWCU) System Isolation – Reactor Vessel Water Level – Low, Low - Level 2

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

Vessel Water Level – Low, Low - Level 2 Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System. Reactor Vessel Water Level – Low, Low - Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level - Low, Low - Level 2 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level – Low, Low - Level 2 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level – Low, Low Level 2 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level – Low, Low Level 2 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 3 valves.

Actions

A note has been provided to modify the ACTIONs related to RPV Water Inventory Control instrumentation channels. The ACTIONs for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for each inoperable RPV Water Inventory Control instrumentation channel.

ACTION a. directs taking the appropriate ACTION referenced in Table 3.3.3.A-1. The applicable ACTION referenced in the table is Function dependent.

RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level Low - Level 3, and Reactor Water Cleanup System Isolation, Reactor Vessel Water Level – Low, Low - Level 2 functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. If the instrumentation is inoperable, ACTION 38 directs immediate action to place the channel in trip. With the inoperable channel in the tripped condition, the remaining channel will isolate the penetration flow path on low water level. If both channels are inoperable and placed in trip, the penetration flow path will be isolated. Alternatively, ACTION 38 requires the associated penetration flow path(s) to be immediately declared incapable of automatic isolation and directs initiating action to calculate of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

INSTRUMENTATION

BASES

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

3.3.1, 3.3.2, and 3.3.4.1

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order 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.

Unit 2

Revised Technical Specifications Bases (For Information Only)

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

TS Bases 3/4.3.3
Insert 1

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3~~.A~~ REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation

3/4.3.3 REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, “Reactor Pressure Vessel (RPV) Water Inventory Control (WIC),” and the definition of DRAIN TIME. There are functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure. It is assumed, based on engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function-by-Function basis.

RHR System Isolation – Reactor Vessel Water Level Low - Level 3

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level Low - Narrow Range Level 3

Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level Low - Narrow Range Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level Low - Narrow Range Level 3 Function are available, only three channels are required to be OPERABLE.

The Reactor Vessel Water Level Low - Narrow Range Level 3 Allowable Value was chosen to be the same as the Plant Protection System Instrumentation Channel Reactor Vessel Water Level Low - Narrow Range Level 3 Allowable Value (Table 3.3.1-1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level Low - Narrow Range Level 3 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 2 valves.

<u>Reactor Water Cleanup (RWCU) System Isolation – Reactor Vessel Water Level – Wide Range Low, Low - Level 2</u>

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level – Wide Range Low, Low - Level 2Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System. Reactor Vessel Water Level – Wide Range Low, Low - Level 2signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level - Low, Low - Level 2 Function are available, only three channels are required to be OPERABLE.

The Reactor Vessel Water Level – Wide Range Low, Low - Level 2 Allowable Value was chosen to be the same as the Plant Protection System Instrument Channels Reactor Vessel Water Level – Low, Low Level 2 Allowable Value (Table 3.3.1-1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level – Low, Low Level 2 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 3 valves.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Actions

A note has been provided to modify the ACTIONs related to RPV Water Inventory Control instrumentation channels. The ACTIONs for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for each inoperable RPV Water Inventory Control instrumentation channel.

ACTION a. directs taking the appropriate ACTION referenced in Table 3.3.3.A-1. The applicable ACTION referenced in the table is Function dependent.

RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level Low - Level 3, and Reactor Water Cleanup System Isolation, Reactor Vessel Water Level – Wide Range Low, Low - Level 2functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. If the required instrumentation is inoperable, ACTION 20 directs immediate action to place the channel in trip. With the inoperable channel in the tripped condition, the remaining channels will isolate the penetration flow path on low water level. If two or more channels are inoperable and placed in trip, the penetration flow path will be isolated. Alternatively, ACTION 20 requires the associated penetration flow path(s) to be immediately declared incapable of automatic isolation and directs initiating action to calculate of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

if they will be isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC)," and the definition of DRAIN TIME. There are functions that are required for manual initiation or operation of the ECCS injection/spray subsystem required to be OPERABLE by LCO 3.5.2 and other functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

The RPV Water Inventory Control Instrumentation supports operation of the Core Spray System (CSS) and the Low Pressure Coolant Injection (LPCI) system. The equipment involved with each of these systems is described in the Bases for LCO 3.5.2.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not postulated in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is postulated in which a single operator error or initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure, e.g., seismic event, loss of normal power, or single human error. It is assumed, based on engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function-by-Function basis.

Core Spray Systems - Reactor Vessel Pressure - Low (Permissive) and Low Pressure Coolant Injection Mode of RHR System - Injection Valve Differential Pressure - Low (Permissive)

The low reactor vessel pressure signal for Core Spray and the injection valve low differential pressure signal for LPCI are used as permissives for the low pressure ECCS injection/spray subsystem manual injection functions. These functions ensure that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. While it is assured during OPERATIONAL CONDITIONS 4 and 5 that the reactor vessel pressure will be below the ECCS maximum design pressure, the Reactor Vessel Pressure - Low signal and the Injection Valve Differential Pressure - Low signal are assumed to be OPERABLE and capable of permitting initiation of the ECCS.

The Reactor Vessel Pressure - Low signals are initiated from four pressure transmitters that sense the reactor vessel pressure. The transmitters are connected to four trip units. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

The Injection Valve Differential Pressure - Low signals are initiated from four differential pressure transmitters (one per valve) that monitor the differential pressure across each LPCI injection valve.

The Allowable Values are low enough to prevent overpressuring the equipment in the low pressure ECCS. The instrument channels of the Reactor Vessel Pressure - Low and Injection Valve Differential Pressure - Low Functions are required to be OPERABLE in OPERATIONAL CONDITIONS 4 and 5 when ECCS manual initiation is required to be OPERABLE by LCO 3.5.2.

Manual Initiation

The Manual Initiation push button channels introduce signals into the appropriate ECCS logic to provide manual initiation capability. There is one push button for each of the CSS and LPCI subsystems (i.e., four for CSS and four for LPCI).

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons. A channel of the Manual Initiation Function (one channel per subsystem) is required to be OPERABLE in OPERATIONAL CONDITIONS 4 and 5 when the associated ECCS subsystems are required to be OPERABLE per LCO 3.5.2.

RHR System Isolation - Reactor Vessel Water Level Low - Level 3

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level Low - Level 3 Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level Low - Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level Low - Level 3 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level Low - Level 3 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level Low - Level 3 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level Low - Level 3 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 2 valves.

Reactor Water Cleanup (RWCU) System Isolation - Reactor Vessel Water Level - Low, Low - Level 2

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level - Low, Low - Level 2 Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

Reactor Vessel Water Level - Low, Low - Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level - Low, Low - Level 2 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level - Low, Low - Level 2 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level - Low, Low Level 2 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level - Low, Low - Level 2 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 3 valves.

Actions

A note has been provided to modify the ACTIONs related to RPV Water Inventory Control instrumentation channels. The ACTIONs for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for each inoperable RPV Water Inventory Control instrumentation channel.

ACTION a. directs taking the appropriate ACTION referenced in Table 3.3.3.A-1. The applicable ACTION referenced in the table is Function dependent.

RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level Low - Level 3, and Reactor Water Cleanup System Isolation, Reactor Vessel Water Level - Low, Low - Level 2 functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. If the instrumentation is inoperable, ACTION 38 directs an immediate declaration that the associated penetration flow path(s) are incapable of automatic isolation and calculation of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

Low reactor vessel pressure signals are used as permissives for the low pressure ECCS injection/spray subsystem manual injection functions. If the permissive is inoperable, manual initiation of ECCS is prohibited. Therefore, the permissive must be placed in the trip condition within 1 hour. With the permissive in the trip condition, manual initiation may be performed. Prior to placing the permissive in the tripped condition, the operator can take manual control of the pump and the injection valve to inject water into the RPV.

The allowed outage time of 1 hour is intended to allow the operator time to evaluate any discovered inoperabilities and to place the channel in trip.

The 24 hour allowed outage time was chosen to allow time for the operator to evaluate and repair any discovered inoperabilities. The allowed outage time is appropriate given the ability to manually start the ECCS pumps and open the injection valves and to manually ensure the pump does not overheat.

With the ACTION and associated allowed outage time of ACTION 39 or 40 not met, the associated low pressure ECCS injection/spray subsystem may be incapable of performing the intended function, and must be declared inoperable immediately.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81 "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

3/4.3.1, 3/4.3.2, 3/4.3.4.1

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order 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.

Specification 3/4.3.4.1, Anticipated Transient Without Scram Recirculation Pump Trip System Instrumentation

Unit 1

Current Technical Specifications Markup

INSTRUMENTATION

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~~. D01

APPLICABILITY: OPERATIONAL CONDITION 1. D02

ACTION: Note: Separate condition entry is allowed for each trip function.

~~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.~~ D01

a. ~~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*~~. D02

Insert 1

~~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.~~ D02

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

c. ~~d.~~ With one ~~trip system~~ subsystem inoperable, restore the inoperable ~~trip system~~ subsystem 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. D02

d. ~~e.~~ With both ~~trip systems~~ subsystems inoperable, restore at least one ~~trip system~~ subsystem 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.~~ D02

Specification 3/4.3.4.1

Insert 1

b. With the number of OPERABLE channels two or more less than the Minimum OPERABLE Channels, restore at least two channels to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

TABLE 3.3.4.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM *~~
1. Reactor Vessel Water Level - Wide Range, Low Low, Level 2	3 ~~2~~
2. Reactor Vessel Steam Dome Pressure - High	3 ~~2~~

D03

D04

~~* One channel may be placed in an inoperable status for up to 6 hours for required surveillance provided the other channel is OPERABLE.~~

D03

PTS
3.3.4.1

TS 3.3.4.1

TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION ~~SETPOINTS~~ ALLOWABLE VALUES

D01

TRIP FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE
1. Reactor Vessel, Water Level - Wide Range, Low Low, Level 2	~~≥ -38 inches*~~	≥ -45 inches
2. Reactor Vessel Steam Dome Pressure - High	~~≤ 1149 psig~~	≤ 1156 psig

D04

~~* See Bases Figure B3/4 3-1.~~

D01

Unit 2

Current Technical Specifications Markup

INSTRUMENTATION

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.~~ D01

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION: Note: Separate condition entry is allowed for each trip function. D02

~~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.~~ D01

a. ~~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*~~. D02

Insert 1

~~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.~~ D02

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

c. ~~d.~~ With one ~~trip system~~ subsystem inoperable, restore the inoperable ~~trip system~~ subsystem 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. D02

d. ~~e.~~ With both ~~trip systems~~ subsystems inoperable, restore at least one ~~trip system~~ subsystem 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.~~ D02

Specification 3/4.3.4.1

Insert 1

b. With the number of OPERABLE channels two or more less than the Minimum OPERABLE Channels, restore at least two channels to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

TABLE 3.3.4.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS ~~PER TRIP SYSTEM *~~
1. Reactor Vessel Water Level - Wide Range, Low Low, Level 2	3 ~~2~~
2. Reactor Vessel Steam Dome Pressure - High	3 ~~2~~

D03

D04

D03

~~* One channel may be placed in an inoperable status for up to 6 hours for required surveillance provided the other channel is OPERABLE.~~

TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION ~~SETPOINTS~~ ALLOWABLE VALUES

TRIP FUNCTION	~~TRIP SETPOINT~~	ALLOWABLE VALUE	D01
1. Reactor Vessel, Water Level - Wide Range, Low Low, Level 2	~~≥ -38 inches*~~	≥ -45 inches	
2. Reactor Vessel Steam Dome Pressure - High	~~≤ 1149 psig~~	≤ 1156 psig	

D04

~~* See Bases Figure B3/4.3-1.~~ D01

Discussion of Changes

Discussion of Changes

Technical Specification 3/4.3.4.1
ATWS Recirculation Pump Trip System Instrumentation

D01

Current TS 3/4.3.4.1, "Anticipated Transient Without Scram (ATWS) Recirculation Pump Trip System Instrumentation," requires the instrument channels to be operable with their trip setpoints set consistent with the values in Table 3.3.4.1-2. Table 3.3.4.1-2 contains both a Trip Setpoint and an Allowable Value for each Trip Function. However, the corresponding Action a only requires the channel to be declared inoperable if the setpoint is less conservative than the Allowable Value. The proposed TS relocates the trip setpoints in Table 3.3.4.1-2 to licensee control and Action a is eliminated. Table 3.3.4.1-2 is relabeled from "ATWS Recirculation Pump Trip System Instrumentation Setpoints" to "ATWS Recirculation Pump Trip System Instrumentation Allowable Values."

The purpose of the trip setpoint requirements is to ensure required automatic safety systems are actuated to protect against violating core design limits, breaching the RCS pressure boundary, and to mitigate accidents. In accordance with 10 CFR 50.36(c)(1)(ii)(A), if it is determined that an automatic protective device for a variable on which a safety limit has been placed (i.e., a limiting safety system setting) does not function as required, appropriate action must be taken to ensure the abnormal situation is corrected before a safety limit is exceeded, which may include shutting down the reactor. The CEG instrument setpoint methodology follows General Electric (GE) Topical Report NEDC-31336P, "General Electric Instrument Setpoint Methodology," which has been found to be acceptable by the NRC for selecting instrumentation setpoints (i.e., ADAMS Accession No. ML20044B611). Additionally, pre-defined limits (i.e., as-found limits and as-left limits) are determined for each instrument consistent with the guidance provided in RG 1.105 and ANSI/ISA-RP67.04.

The removal of these details from the TS is acceptable because this type of information is not necessary to provide adequate protection of public health and safety. The proposed TS retain the Allowable Values associated with the ATWS Recirculation Pump Trip System Instrumentation, which are designated as the operability limits for the required Functions. Also, this change is acceptable because these types of procedural details will be adequately controlled under the requirements of 10 CFR 50.59, which ensures changes are properly evaluated.

The removal of Action a and the relabeling of Table 3.3.4.1-2 are changes made to be consistent with the relocation of the trip setpoints.

D02

Current TS 3.3.4.1, Actions are based on the current "one out of two taken twice" instrumentation logic and the Minimum Operable Channels requirement for both functions of two channels per trip system. As described in Discussion of Changes for Technical Specification 3/4.3.3, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation" (i.e., Discussion of Change D03), under the proposed change the term "trip system" is no longer applicable and the Minimum Operable Channels is changed to 3 to reflect the new design. This affects Actions b, c, d, and e.

Current Action b applies when the number of operable channels is one less than the Minimum Operable Channels per Trip System for one or both trip systems. With one channel inoperable in one or both trip systems, the system can generate a trip but cannot do so with a concurrent single failure. In the proposed TS, Action b is renamed Action a and references to the trip systems are removed. With one of the three required channels inoperable, the system can generate a trip but cannot do so with a concurrent single failure. As the level of degradation is the same, the existing Action to place the inoperable channel in trip within 24 hours is retained. The Footnote *, which states, "Not applicable when trip capability is not maintained," is deleted as trip capability is always maintained with one required channel inoperable under the new design.

A new Action b is added which is applicable when the number of operable channels is two or more less than the Minimum Operable Channels. This level of degradation is consistent with the current Action applicable when two trip systems are inoperable. Therefore, the same action is applied. At least two channels must be restored to operable status within 1 hour or be in at least Startup within the next 6 hours.

Current Action c applies when the number of operable channels is two or more less than the Minimum Operable Channels per Trip System in one trip system. Action c.1 and c.2 require declaring the affected trip system inoperable. Action d applies when one trip system is inoperable. The new design does not include trip systems, therefore, Action c.1, c.2, and d are no longer applicable and are removed. Because the actions that are based on combinations of inoperable trip functions are removed, the remaining actions are applicable independently to each trip function. A note stating that separate condition entry is allowed for each trip function is added to the Actions.

Current Action d applies when one trip system is inoperable. The term "trip system" is no longer applicable under the new design, but the ATWS Recirculation Pump Trip System Instrumentation contains two trip relays. The action is revised to refer to "subsystems " instead of "trip systems," and renumbered Action c. The term "subsystem" is used to encompass the entire trip subsystem from the PPS output device to the recirculation pump circuit breaker. The TS Bases will describe the subsystem. Similarly, current Action e applies when two trip systems are inoperable. This action is also revised to refer to "subsystems " instead of "trip systems," and renumbered Action d. The TS Bases will describe the subsystem. The proposed changes to the Actions are appropriate as they retain similar Actions for similar levels of degradation under the new design.

D03

Current TS 3.3.4.1, Table 3.3.4.1-1 contains a column labeled, "Minimum Operable Channels per Trip System." For the two functions in the Table, the entries are "2". In the proposed TS, the column is relabeled "Minimum Operable Channels," and the entries for both functions are changed to "3" to reflect the new design.

As discussed in Section 9.6 of the PPS Licensing Technical Report, the instrumentation logic for the two functions in Table 3.3.4.1-1, Function 1, "Reactor Vessel Water Level - Low - Level 3," and Function 2, "Reactor Vessel Pressure - High," is changed from "one out of two taken twice" to "two out of four." Any two channels exceeding the setpoint will result in actuation of the system and the term "trip systems" is no longer applicable under the new design.

Under the revised design any three channels provide the required independence and redundancy. Therefore, the Minimum Operable Channels is changed to three. The proposed change is acceptable because it reflects the new design of the affected functions and ensures that systems assumed to automatically actuate will do so when the Allowable Value is not met.

D04

Current TS 3.3.4.1, Table 3.3.4.1-1 and Table 3.3.4.1-2, contain two functions, Function 1, "Reactor Vessel, Water Level – Low Low, Level 2," and Function 2, "Reactor Vessel Pressure - High." These functions are renamed to be consistent with the function nomenclature used in proposed TS 3.3.1. Function 1, "Reactor Vessel, Water Level - Low Low, Level 2," is renamed "Reactor Vessel, Water Level Wide Range - Low Low, Level 2." Function 2, "Reactor Vessel Pressure - High," is renamed "Reactor Vessel Steam Dome Pressure - High." The proposed change is acceptable because is maintains consistency within the TS without introducing any technical changes.

Unit 1

Proposed Technical Specifications

INSTRUMENTATION

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.1 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.

APPLICABILITY: OPERATIONAL CONDITION 1.

Note: Separate condition entry is allowed for each trip function.

ACTION:

b. a. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, place the inoperable channel(s) in the tripped condition within 24 hours.

b. With the number of OPERABLE channels two or more less than the Minimum OPERABLE Channels, restore at least two channels to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

d. c. With one subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours, or be in at least STARTUP within the next 6 hours.

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

SURVEILLANCE REQUIREMENTS

4.3.4.1.1 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 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.

TABLE 3.3.4.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

	TRIP FUNCTION	MINIMUM OPERABLE CHANNELS
1.	Reactor Vessel Water Level - Wide Range, Low Low, Level 2	3
2.	Reactor Vessel Steam Dome Pressure - High	3

TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION ALLOWABLE VALUES

TRIP FUNCTION	ALLOWABLE VALUE
1. Reactor Vessel, Water Level - Wide Range, Low Low, Level 2	≥ -45 inches
2. Reactor Vessel Steam Dome Pressure - High	≤ 1156 psig

Unit 2

Proposed Technical Specifications

INSTRUMENTATION

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.

APPLICABILITY: OPERATIONAL CONDITION 1.

Note: Separate condition entry is allowed for each trip function.

ACTION:

a. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, place the inoperable channel(s) in the tripped condition within 24 hours.

b. With the number of OPERABLE channels two or more less than the Minimum OPERABLE Channels, restore at least two channels to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

c. With one subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours, or be in at least STARTUP within the next 6 hours.

d. With both subsystems inoperable, restore at least one subsystem 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.

TABLE 3.3.4.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

	TRIP FUNCTION	MINIMUM OPERABLE CHANNELS
1.	Reactor Vessel Water Level - Wide Range, Low Low, Level 2	3
2.	Reactor Vessel Steam Dome Pressure - High	3

TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION ALLOWABLE VALUES

TRIP FUNCTION	ALLOWABLE VALUE
1. Reactor Vessel, Water Level - Wide Range, Low Low, Level 2	$\geq$ -45 inches
2. Reactor Vessel Steam Dome Pressure - High	$\leq$ 1156 psig

Unit 1

Revised Technical Specifications Bases (For Information Only)

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

3/4.3.3

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

Insert 1

~~3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION~~

~~The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.~~

3/4.3.4.2

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order 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.

3/4.3.4.1 ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

ATWS RPT instruments are the same detectors used by PPS; however, the signal is isolated to permit connection to the non-safety Distributed Control System. Refer to Specification 3.3.1 Functions 3 and 4.

Unit 2

Revised Technical Specifications Bases (For Information Only)

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81 "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

3/4.3.3

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

Insert 1

~~3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION~~

~~The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.~~

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order 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.

3/4.3.4.2

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.

3/4.3.4.1 ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

ATWS RPT instruments are the same detectors used by PPS; however, the signal is isolated to permit connection to the non-safety Distributed Control System. Refer to Specification 3.3.1 Functions 3 and 4.

Specification 3/4.3.4.2, End-of-Cycle Recirculation Pump Trip System Instrumentation

Unit 1

Current Technical Specifications Markup

PTS

INSTRUMENTATION

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

3.3.4.2 Two end-of-cycle recirculation pump trip (EOC-RPT) subsystems shall be OPERABLE.

LIMITING CONDITION FOR OPERATION

D01

3.3.1 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.~~ D02

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

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.

3.3.1 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 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 turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within 12 hours or in accordance with the Risk Informed Completion Time Program.

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

a ~~d~~. With one subsystem ~~trip system~~ inoperable, restore the inoperable subsystem ~~trip system~~ to OPERABLE status within 72 hours ~~or in accordance with the Risk Informed Completion Time Program,~~ or take the ACTION required by Specification 3.2.3. D01

b ~~e~~. With both subsystems ~~trip systems~~ inoperable, restore at least one subsystem ~~trip system~~ to OPERABLE status within one hour or take the ACTION required by Specification 3.2.3. D01

3.3.1 *Not applicable when trip capability is not maintained.

INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

3.3.1 4.3.4.2.1 Each of the required end-of-cycle recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST, including trip system logic testing, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

~~4.3.4.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program~~. D03

Insert 1

subsystem

4.3.4.2.~~3~~ 2 The END-OF-CYCLE RECIRCULATION subsystem PUMP TRIP SYSTEM RESPONSE TIME of each ~~trip function shown in Table 3.3.4.2-3~~ shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit. D01

4.3.4.2.~~4~~ 3 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured in accordance with the Surveillance Frequency Control Program.

Specification 3/4.3.4.2

Insert 1

4.3.4.2.1 Verify the Plant Protection System provides a signal from each division to each EOC RPT subsystem and the recirculation pump trip breakers in accordance with the Surveillance Frequency Control Program.

TABLE 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

3.3.1

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM*
1. Turbine Stop Valve - Closure	2**
2. Turbine Control Valve-Fast Closure	2**

* A trip system may be placed in an inoperable status for up to 6 hours for required surveillance provided that the other trip system is OPERABLE.

** This function shall be automatically bypassed when turbine first stage pressure is equivalent to THERMAL POWER LESS than 29.5% of RATED THERMAL POWER.

PTS

TABLE 3.3.4.2-2

END-OF-CYCLE RECIRCULATION PUMP TRIP SETPOINTS

3.3.1

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Turbine Stop Valve-Closure	$\leq$ 5% closed	$\leq$ 7% closed
2. Turbine Control Valve-Fast Closure	$\geq$ 500 psig	$\geq$ 465 psig

~~TABLE 3.3.4.2-3~~

~~END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME~~

D02

~~TRIP FUNCTION~~	~~RESPONSE TIME (Milliseconds)~~
~~1. Turbine Stop Valve-Closure~~	~~$\leq$ 175~~
~~2. Turbine Control Valve-Fast Closure~~	~~$\leq$ 175~~

Unit 2

Current Technical Specifications Markup

3.3.4.2 Two end-of-cycle recirculation pump trip (EOC-RPT) subsystems shall be OPERABLE.

INSTRUMENTATION

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 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.~~ D01 D02

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

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

3.3.1

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 or in accordance with the Risk Informed Completion Time Program.

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

a ~~d.~~ With one subsystem ~~trip system~~ inoperable, restore the inoperable subsystem ~~trip system~~ to OPERABLE status within 72 hours ~~or in accordance with the Risk Informed Completion Time Program~~, or take the ACTION required by Specification 3.2.3. D01

b ~~e.~~ With both subsystems ~~trip systems~~ inoperable, restore at least one subsystem ~~trip system~~ to OPERABLE status within one hour or take the ACTION required by Specification 3.2.3. D01

3.3.1 *Not applicable when trip capability is not maintained.

INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

3.3.1 4.3.4.2.1 Each of the required end-of-cycle recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST, including trip system logic testing, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

D03

~~4.3.4.2.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program~~.

subsystem

4.3.4.2.~~3~~ 2 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each ~~trip function shown in Table 3.3.4.2-3~~ shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit.

D01

4.3.4.2.~~4~~ 3 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured in accordance with the Surveillance Frequency Control Program.

Insert 1

Specification 3/4.3.4.2

Insert 1

4.3.4.2.1 Verify the Plant Protection System provides a signal from each division to each EOC RPT subsystem and the recirculation pump trip breakers in accordance with the Surveillance Frequency Control Program.

TABLE 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM*
1. Turbine Stop Valve - Closure	2**
2. Turbine Control Valve-Fast Closure	2**

3.3.1

* A trip system may be placed in an inoperable status for up to 6 hours for required surveillance provided that the other trip system is OPERABLE.

** This function shall be automatically bypassed when turbine first stage pressure is equivalent to THERMAL POWER LESS than 29.5% of RATED THERMAL POWER.

PTS

TABLE 3.3.4.2-2

END-OF-CYCLE RECIRCULATION PUMP TRIP SETPOINTS

3.3.1

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Turbine Stop Valve-Closure	≤ 5% closed	≤ 7% closed
2. Turbine Control Valve-Fast Closure	≥ 500 psig	≥ 465 psig

~~TABLE 3.3.4.2-3~~

~~END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME~~

~~TRIP FUNCTION~~	~~RESPONSE TIME (Milliseconds)~~
~~1. Turbine Stop Valve-Closure~~	~~$\leq$ 175~~
~~2. Turbine Control Valve-Fast Closure~~	~~$\leq$ 175~~

D02

Discussion of Changes

Discussion of Changes

Technical Specification 3/4.3.4.2
End-of-Cycle Recirculation Pump Trip System Instrumentation

D01

Current TS 3/4.3.4.2, "End-of-Cycle (EOC) Recirculation Pump Trip System Instrumentation," Table 3.3.4.2-1 contains instrumentation channel requirements for two sensing channels, Function 1, "Turbine Stop Valve – Closure," and Function 2, "Turbine Control Valve - Fast Closure," and the recirculation pump trip logic. In the proposed TS, the two sensing channels are relocated to TS 3.3.1, and the recirculation pump trip logic is retained in TS 3.3.4.2.

The two functions in the current TS 3.3.4.2 are also used for reactor trip and are processed by the PPS. Therefore, these functions should be included in TS 3.3.1. The conditions that result in an EOC Recirculation Pump Trip (EOC-RPT) signal are determined by the PPS. However, the PPS output signals use cabling, trip coils, and 4kV breakers to trip the recirculation pumps. It is not appropriate to declare the PPS division inoperable if one of these components is inoperable. Therefore, that portion of the EOC-RPT Instrumentation system is retained in Specification 3/4.3.4.2 and labeled "subsystems," which are described in the TS Bases. Because the functioning of the system is changed by the installation of the PPS, the existing RICT in current Action d. is removed.

This change is acceptable because it accurately reflects the functional division of the system between the PPS channels, divisions, and the EOC-RPT actuation logic without changing the technical requirements.

D02

The current TS 3.3.4.2 LCO requirement for the EOC-RPT Response Time to be within the limits of Table 3.3.4.2.3, the reference to Table 3.3.4.2-3 in SR 4.3.4.2.3, and Table 3.3.4.2-3 are removed in the proposed TS. SR 4.3.4.2.3 continues to require the EOC-RPT Response Time to be demonstrated to be within the limit, but the limits have been relocated to licensee control.

The response time limits in Table 3.3.4.2-3 are relocated to licensee control under the controls of 10 CFR 50.59. This change is consistent with the guidance in Generic Letter 93-08. The surveillances will continue to require the system to be operable with response times within limit. Relocating the tables of instrument response time limits from the TS to a document controlled under 10 CFR 50.59 will not alter this surveillance requirement. The plant procedures for response time testing include acceptance criteria that reflect the response time limits in the table being relocated. The response time limits will be included in the TS Bases. This change is acceptable because the TS continue to require verification that the response time limits are met, and the limits are controlled under the appropriate regulatory process.

D03
Current SR 4.3.4.2.2 requires performance of a Logic System Functional Test (LSFT) and simulated automatic operation of all EOC-RPT channels. The LSFT is defined in Chapter 1 as:

> "A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all logic components, i.e., all relays and contacts, all trip units, solid state logic elements, etc, of a logic circuit, from sensor through and including, the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by any series of sequential, overlapping or total system steps such that the entire logic system is tested."

The proposed TS replaces this test requirement with a verification that the PPS provides a signal from each division to each EOC-RPT System Instrumentation subsystem and the recirculation pump trip breakers. Both the current LSFT test and the proposed test are performed at a frequency established by the SFCP. The Turbine Stop Valve - Closure and Turbine Control Valve - Fast Closure, Functions that support the EOC-RPT System Instrumentation are moved to TS 3.3.1. Proposed SR 4.3.1.1 requires performance of a Sensor Channel Calibration which tests from the sensor output to the input to the PPS. The PPS self-test capability tests the PPS from the input to the output of an EOC-RPT signal. The proposed Surveillance Requirement will test from the EOC-RPT signal from the output of the PPS, through the EOC-RPT logic, to the recirculation pump 4kV circuit breakers. The proposed change is acceptable because the combination of these tests performs the same function as the current LSFT requirement.

Unit 1

Proposed Technical Specifications

CTS

INSTRUMENTATION

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 3.3.4.2 Two end-of-cycle recirculation pump trip (EOC-RPT) subsystems shall be OPERABLE.

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

ACTION;

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

e. b. With both subsystems inoperable, restore at least one subsystem to OPERABLE status within one hour or take the ACTION required by Specification 3.2.3.

CTS

INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Verify the Plant Protection System provides a signal from each division to each EOC RPT subsystem and the recirculation pump trip breakers in accordance with the Surveillance Frequency Control Program.

4.3.4.2.3 4.3.4.2.2 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each subsystem shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit.

4.3.4.2.4 4.3.4.2.3 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured in accordance with the Surveillance Frequency Control Program.

Unit 2

Proposed Technical Specifications

See Unit 1
Markup for
CTS
References

INSTRUMENTATION

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 Two end-of-cycle recirculation pump trip (EOC-RPT) subsystems shall be OPERABLE.

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

ACTION;

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

b. With both subsystems inoperable, restore at least one subsystem to OPERABLE status within one hour or take the ACTION required by Specification 3.2.3.

INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Verify the Plant Protection System provides a signal from each division to each EOC RPT subsystem and the recirculation pump trip breakers in accordance with the Surveillance Frequency Control Program.

4.3.4.2.2 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each subsystem shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit.

4.3.4.2.3 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured in accordance with the Surveillance Frequency Control Program.

Unit 1

Revised Technical Specifications Bases (For Information Only)

INSTRUMENTATION

BASES

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

3/4.3.3

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

Inputs for EOC RPT function are provided by Turbine Stop Valve-Closure sensors and Turbine Control Valve Fast Closure, Trip Oil Pressure -Low, using standard 2oo4 voting logic. (Table 3.3.1-1 items 20 and 21 respectively). Upon receipt of a valid vote for either parameter, all EOC RPT trip coils will energize.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order 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.~~

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, ~~i.e., 175 ms~~. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression, and the response time of the system logic.

TS Bases 3/4.3.4.2
Insert 1

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each division is completed within the time limit assumed in the safety analyses.

TABLE B 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESONSE TIME

TABLE 3.3.1-1 FUNCTION *	RESPONSE TIME (Seconds)
20. Turbine Stop Valve - Closure b. End-of-Cycle Recirculation Pump Trip System	< 175 milliseconds
21. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low b. End-of-Cycle Recirculation Pump Trip System	< 175 milliseconds

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

~~Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.~~

Not affected

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions 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. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage time have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

Unit 2

Revised Technical Specifications Bases (For Information Only)

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81 "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

3/4.3.3 2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

Inputs for EOC RPT function are provided by Turbine Stop Valve-Closure sensors and Turbine Control Valve Fast Closure, Trip Oil Pressure -Low, using standard 2oo4 voting logic. (Table 3.3.1-1 items 20 and 21 respectively). Upon receipt of a valid vote for either parameter, all EOC RPT trip coils will energize.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order 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.~~

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc~~, i.e., 175 ms~~. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression, and the response time of the system logic.

TS Bases 3/4.3.4.2
Insert 1

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each division is completed within the time limit assumed in the safety analyses.

TABLE B 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESONSE TIME

TABLE 3.3.1-1 FUNCTION *	RESPONSE TIME (Seconds)
20. Turbine Stop Valve - Closure b. End-of-Cycle Recirculation Pump Trip System	< 175 milliseconds
21. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low b. End-of-Cycle Recirculation Pump Trip System	< 175 milliseconds

INSTRUMENTATION

BASES

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

~~Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.~~

Not affected

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions 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. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage time have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

Specification 3/4.3.5, Loss of Power Instrumentation

Unit 1

Current Technical Specifications Markup

PTS

INSTRUMENTATION

~~3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~

3/4.3.5 LOSS OF POWER INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

D01

~~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.~~ D01

3.3.5 The Loss of Power instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: ~~As shown in Table 3.3.3-1~~

OPERATIONAL CONDITIONS 1, 2, 3, 4**, and 5**

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.~~ D02

3.5.1 Actions a and b

b. ~~With one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.3-1.~~ D01

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

3.3.1

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

4.3.5.1 and 4.3.5.2

~~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.~~ D01

Insert 1

4.3.5.3 4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all Loss of Power 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.~~ D04

Specification 3/4.3.5

Insert 1

4.3.5.1 The Loss of Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST at the frequencies specified in the Surveillance Frequency Control Program. The Loss of Voltage Relay 127-11X is not field setable.

4.3.5.2 The Degraded Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

3.3.5

TABLE ~~3.3.3~~-1 (Continued)

LOSS OF POWER INSTRUMENTATION

D01

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~

3.3.1 and 3.3.2

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[(a)]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
4. AUTOMATIC DEPRESSURIZATION SYSTEM#***			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2	1, 2, 3	30
b. Drywell Pressure - High	2	1, 2, 3	30
c. ADS Timer	1	1, 2, 3	31
d. Core Spray Pump Discharge Pressure - High (Permissive)	2	1, 2, 3	31
e. RHR LPCI Mode Pump Discharge Pressure High (Permissive)	4	1, 2, 3	31
f. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
g. Manual Initiation	2	1, 2, 3	33
h. ADS Drywell Pressure Bypass Timer	2	1, 2, 3	31

MINIMUM OPERABLE CHANNELS

D03

Table 3.3.5-1

	~~TOTAL NO. OF CHANNELS(f)~~	~~CHANNELS TO TRIP~~	~~MINIMUM CHANNELS OPERABLE~~	APPLICABLE OPERATIONAL CONDITIONS	ACTION 3.3.5 Actions a & b
5. LOSS OF POWER					
1. 4.16 Kv Emergency Bus Under-voltage (Loss of Voltage)	~~1/bus~~	~~1/bus~~	1/bus	1,2,3,4**,5**	~~36~~
2. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	~~1/source/bus~~	~~1/source/bus~~	1/source/bus	1,2,3,4**,5**	~~37~~

D01

Applicability

D03

3.3.1 and 3.3.2

***The Minimum OPERABLE Channels Per Trip Function is per subsystem.

PTS

~~TABLE 3.3.3-1 (Continued)~~
~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~
~~TABLE NOTATIONS~~

D01

3.3.1

(a) 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 provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

(b) Also provides input to actuation logic for the associated emergency diesel generators.

(c) One trip system. Provides signal to HPCI pump suction valves only.

(d) On 1 out of 2 taken twice logic, provides a signal to trip the HPCI pump turbine only.

(e) The manual initiation push buttons start the respective core spray pump and diesel generator. The "A" and "B" logic manual push buttons also actuate an initiation permissive in the injection valve opening logic.

Table 3.3.5-1 Note (a)

(~~f~~) a A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2. D01

3.3.1

* DELETED

\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

3.3.5 Applicability

** Required when ESF equipment is required to be OPERABLE. D01

3.3.1

\## Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

\### The injection functions of Drywell Pressure - High and Manual Initiation are not required to be OPERABLE with reactor steam dome pressure less than 550 psig.

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

D01

3.3.1

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 in accordance with the Risk Informed Completion Time Program, or declare the associated system inoperable.

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

3.3.1 and 3.3.2

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.

3.3.1

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 in accordance with the Risk Informed Completion Time Program*, 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 in accordance with the Risk Informed Completion Time Program, 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 in accordance with the Risk Informed Completion Time Program*, or declare the HPCI system inoperable.

3.3.5 Action a

D03

D01

~~ACTION 36 -~~ With the number of OPERABLE Loss of Voltage channels less than the ~~Total Number of~~ Minimum Operable 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.

3.3.1

*Not applicable when trip capability is not maintained.

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

D01

Degraded Voltage

Minimum Operable

D03

3.3.5 Action b. ~~ACTION 37 -~~ With the number of OPERABLE channels one less than the ~~Total Number of~~ Channels, place the inoperable device in the bypassed condition subject to the following conditions:

D01

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable.
	127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

TABLE 3.3.5-2

LOSS OF POWER ALLOWABLE VALUES

D01

~~TABLE 3.3.3-2 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS~~

D02

Table 3.3.5-2

TRIP FUNCTION	RELAY		~~TRIP SETPOINT~~	ALLOWABLE VALUE
5. LOSS OF POWER				
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X		~~NA~~	NA
b. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	127-11X0X and 102-11X0X	a.	4.16 kV Basis ~~2905 ± 115 volts~~	2905 ± 145 volts
		b.	120 V Basis ~~83 ± 3 volts~~	83 ± 4 volts
		c.	~~≤ 1 second time delay~~	≤ 1.5 second time delay
	127Y-11X0X** and 127Y-1-11X0X	a.	4.16 kV Basis ~~3640 ± 91 volts~~	3640 ± 182 volts
		b.	120 V Basis ~~104 ± 3 volts~~	104 ± 5.2 volts
		c.	~~≤ 52 second time delay~~	≤ 60 second time delay
	127Z-11X0X and 162Y-11X0X	a.	4.16 kV Basis ~~3910 ± 11 volts~~	3910 ± 19 volts
		b.	120 V Basis ~~111.7 ± 0.3 volts~~	111.7 ± 0.5 volts
		c.	~~≤ 10 second time delay~~	≤ 11 second time delay
	127Z-11X0X and 162Z-11X0X	a.	4.16 kV Basis ~~3910 ± 11 volts~~	3910 ± 19 volts
		b.	120 V Basis ~~111.7 ± 0.3 volts~~	111.7 ± 0.5 volts
		c.	~~≤ 61 second time delay~~	≤ 64 second time delay

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

~~TABLE 3.3.3-3~~

~~EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES~~

D04

ECCS	RESPONSE TIME (Seconds)
1. CORE SPRAY SYSTEM	≤ 27#
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM	≤ 40#
3. AUTOMATIC DEPRESSURIZATION SYSTEM	N.A.
4. HIGH PRESSURE COOLANT INJECTION SYSTEM	≤ 60#
~~5. LOSS OF POWER~~	~~N.A.~~

3.3.2

D04

3.3.2 # ECCS actuation instrumentation is eliminated from response time testing.

~~TABLE 4.3.3.1-1 (Continued)~~

D01

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

	TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
	4. AUTOMATIC DEPRESSURIZATION SYSTEM#				
3.3.1 and 3.3.2	a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3
	b. Drywell Pressure - High				1, 2, 3
	c. ADS Timer	N.A.			1, 2, 3
	d. Core Spray Pump Discharge Pressure - High				1, 2, 3
	e. RHR LPCI Mode Pump Discharge Pressure - High				1, 2, 3
	f. Reactor Vessel Water Level - Low, Level 3				1, 2, 3
	g. Manual Initiation	N.A.		N.A.	1, 2, 3
	h. ADS Drywell Pressure Bypass Timer	N.A.			1, 2, 3
	5. LOSS OF POWER				Moved to 4.3.5.1 and 4.3.5.2
4.3.5.1	a. 4.16 kV Emergency Bus Under-voltage (Loss of Voltage)##	N.A.		N.A.	1, 2, 3, 4**, 5**
4.3.5.2	b. 4.16 kV Emergency Bus Under - voltage (Degraded Voltage)				1, 2, 3, 4**, 5**

4.3.5.1 and 4.3.5.2 (a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

* ~~DELETED~~

3.3.5 ** Required OPERABLE when ESF equipment is required to be OPERABLE. D01

3.3.1 *** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

Table 3.3.5-2 ## Loss of Voltage Relay 127-11X is not field setable.

Unit 2

Current Technical Specifications Markup

INSTRUMENTATION

~~3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~

3/4.3.5 LOSS OF POWER INSTRUMENTATION

D01

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.~~

D01

3.3.5 The Loss of Power instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: ~~As shown in Table 3.3.3-1~~ OPERATIONAL CONDITIONS 1, 2, 3, 4**, and 5**

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.~~

D02

3.5.1 Actions a and b

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

D01

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

3.3.1

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

4.3.5.1 and 4.3.5.2

~~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.~~

D01

Insert 1

4.3.5.3

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all Loss of Power 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.~~

D04

Specification 3/4.3.5

Insert 1

4.3.5.1 The Loss of Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST at the frequencies specified in the Surveillance Frequency Control Program. The Loss of Voltage Relay 127-11X is not field setable.

4.3.5.2 The Degraded Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

D01

3.3.5

TABLE ~~3.3.3-1~~ (Continued)

LOSS OF POWER INSTRUMENTATION

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
4. AUTOMATIC DEPRESSURIZATION SYSTEM#***			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2	1, 2, 3	30
b. Drywell Pressure - High	2	1, 2, 3	30
c. ADS Timer	1	1, 2, 3	31
d. Core Spray Pump Discharge Pressure - High (Permissive)	2	1, 2, 3	31
e. RHR LPCI Mode Pump Discharge Pressure High (Permissive)	4	1, 2, 3	31
f. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
g. Manual Initiation	2	1, 2, 3	33
h. ADS Drywell Pressure Bypass Timer	2	1, 2, 3	31

3.3.1 and 3.3.2

D03

MINIMUM OPERABLE CHANNELS

	~~TOTAL NO. OF CHANNELS(f)~~	~~CHANNELS TO TRIP~~	~~MINIMUM CHANNELS OPERABLE~~	APPLICABLE OPERATIONAL CONDITIONS	ACTION 3.3.5 Actions a & b
5. LOSS OF POWER					
1. 4.16 kV Emergency Bus Under-voltage (Loss of Voltage)	~~1/bus~~	~~1/bus~~	1/bus	1, 2, 3, 4**, 5**	~~36~~
2. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	~~1/source/ bus~~	~~1/source/ bus~~	1/source/ bus	1, 2, 3, 4**, 5**	~~37~~

D01

Table 3.3.5-1

Applicability

D03

3.3.1 and 3.3.2

***The Minimum OPERABLE Channels Per Trip Function is per subsystem.

PTS

D01

~~TABLE 3.3.3-1 (Continued)~~
~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~
~~TABLE NOTATIONS~~

(a) 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 provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

3.3.1 (b) Also provides input to actuation logic for the associated emergency diesel generators.

(c) One trip system. Provides signal to HPCI pump suction valves only.

(d) On 1 out of 2 taken twice logic, provides a signal to trip the HPCI pump turbine only.

(e) The manual initiation push buttons start the respective core spray pump and diesel generator. The "A" and "B" logic manual push buttons also actuate an initiation permissive in the injection valve opening logic.

Table 3.3.5-1 Note (a) (~~f~~) a A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2. D01

* DELETED

3.3.1 # Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

3.3.5 Applicability ** Required when ESF equipment is required to be OPERABLE. D01

Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

3.3.1 ### The injection functions of Drywell Pressure - High and Manual Initiation are not required to be OPERABLE with reactor steam dome pressure less than 550 psig.

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

D01

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

3.3.1 a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours or in accordance with the Risk Informed Completion Time Program, or declare the associated system inoperable.

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

3.3.1 and 3.3.2 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 in accordance with the Risk Informed Completion Time Program*, or declare the associated ECCS inoperable.

3.3.1

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 in accordance with the Risk Informed Completion Time Program, 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 in accordance with the Risk Informed Completion Time Program*, or declare the HPCI system inoperable.

3.3.5 Action a ~~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.

D03

D01

Loss of Voltage

Minimum Operable

3.3.1 *Not applicable when trip capability is not maintained.

PTS

D01

~~TABLE 3.3.3-1 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION~~

~~ACTION STATEMENTS~~

D03

Degraded Voltage

Minimum Operable

3.3.5 Action b. ~~ACTION 37 -~~ With the number of OPERABLE channels one less than the ~~Total Number of~~ Channels, place the inoperable device in the bypassed condition subject to the following conditions:

D01

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable.
	127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

TABLE 3.3.5-2 LOSS OF POWER ALLOWABLE VALUES

~~TABLE 3.3.3-2 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS~~

D01

Table 3.3.5-2

TRIP FUNCTION			~~TRIP SETPOINT~~	ALLOWABLE VALUE
5. LOSS OF POWER	RELAY			
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X		~~NA~~	NA
b. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	RELAY			
	127-11X0X and 102-11X0X	a.	4.16 kV Basis ~~2905 ± 115 volts~~	2905 ± 145 volts
		b.	120 V Basis ~~83 ± 3 volts~~	83 ± 4 volts
		c.	~~≤ 1 second time delay~~	≤ 1.5 second time delay
	127Y-11X0X** and 127Y-1-11X0X	a.	4.16 kV Basis ~~3640 ± 91 volts~~	3640 ± 182 volts
		b.	120 V Basis ~~104 ± 3 volts~~	104 ± 5.2 volts
		c.	~~≤ 52 second time delay~~	≤ 60 second time delay
	127Z-11X0X and 162Y-11X0X	a.	4.16 kV Basis ~~3910 ± 11 volts~~	3910 ± 19 volts
		b.	120 V Basis ~~111.7 ± 0.3 volts~~	111.7 ± 0.5 volts
		c.	~~≤ 10 second time delay~~	≤ 11 second time delay
	127Z-11X0X and 162Z-11X0X	a.	4.16 kV Basis ~~3910 ± 11 volts~~	3910 ± 19 volts
		b.	120 V Basis ~~111.7 ± 0.3 volts~~	111.7 ± 0.5 volts
		c.	~~≤ 61 second time delay~~	≤ 64 second time delay

D02

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

PTS

D04

~~TABLE 3.3.3-3~~

~~EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES~~

ECCS		RESPONSE TIME (Seconds)
1.	CORE SPRAY SYSTEM	≤ 27#
2.	LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM	≤ 40#
3.	AUTOMATIC DEPRESSURIZATION SYSTEM	N.A.
4.	HIGH PRESSURE COOLANT INJECTION SYSTEM	≤ 60#
~~5.~~	~~LOSS OF POWER~~	~~N.A.~~

3.3.2

D04

3.3.2

ECCS actuation instrumentation is eliminated from response time testing.

D01

~~TABLE 4.3.3.1-1 (Continued)~~

~~EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

	TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
	4. AUTOMATIC DEPRESSURIZATION SYSTEM#				
3.3.1 and 3.3.2	a. Reactor Vessel Water Level - Low Low Low, Level 1				1, 2, 3
	b. Drywell Pressure - High				1, 2, 3
	c. ADS Timer	N.A.			1, 2, 3
	d. Core Spray Pump Discharge Pressure - High				1, 2, 3
	e. RHR LPCI Mode Pump Discharge Pressure - High				1, 2, 3
	f. Reactor Vessel Water Level - Low, Level 3				1, 2, 3
	g. Manual Initiation	N.A.		N.A.	1, 2, 3
	h. ADS Drywell Pressure Bypass Timer	N.A.			1, 2, 3
	5. LOSS OF POWER				
4.3.5.1	a. 4.16 kV Emergency Bus Under voltage (Loss of Voltage)##	N.A.		N.A.	1, 2, 3, 4**, 5**
4.3.5.2	b. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)				1, 2, 3, 4**, 5**

Moved to 4.3.5.1 and 4.3.5.2

4.3.5.1 and 4.3.5.2

(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

~~* DELETED~~

3.3.5 ** Required OPERABLE when ESF equipment is required to be OPERABLE.

D01

3.3.1 *** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

Loss of Voltage Relay 127-11X is not field setable.

Table 3.3.5-2

Discussion of Changes

Discussion of Changes

Technical Specification 3/4.3.5
Loss of Power Instrumentation

D01

Current TS 3.3.3, Table 3.3.3-1, includes Trip Function 5, "Loss of Power." The requirements associated with this Trip function are moved to a new TS 3.3.5, "Loss of Power Instrumentation," with no technical changes. This reorganization of requirements includes:

- Creation of LCO 3.3.5, which states, "The Loss of Power instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE."
- Movement of the "Applicable Operational Conditions" requirement from Table 3.3.3-1 and the "Operational Conditions for Which Surveillance Required," requirement from Table 4.3.3.1-1, as well as the associated footnotes, to the "Applicability" section of the new specification.
- Movement of the Actions 36 and 37 associated with Loss of Power in Table 3.3.3-1 to new Actions a and b in the Actions section of the new specification and elimination of existing Action b which states to follow the Actions in the Table 3.3.3-1.
- Movement of the Surveillance Requirements and associated footnote from Table 4.3.3.1-1 to the Surveillance Requirement section of the specification.

The proposed changes are acceptable because the reorganization of the existing requirements into a new specification does not result in any technical changes to the requirements. In addition, the proposed change is consistent with the NRC's Standard Technical Specifications in NUREG-1433, "Standard Technical Specifications, General Electric BWR/4 Plants."

D02

Current TS 3.3.3 requires the instrument channels to be operable with their trip setpoints set consistent with the values in Table 3.3.3-2. TS Table 3.3.3-2 contains both a Trip Setpoint and an Allowable Value for each Trip Function. However, the corresponding Action a only requires the channel to be declared inoperable if the setpoint is less conservative than the Allowable Value. The proposed TS relocates the trip setpoints in Table 3.3.3-2 to licensee control and Action a is eliminated.

The purpose of the trip setpoint requirements is to ensure required automatic safety systems are actuated to protect against violating core design limits, breaching the RCS pressure boundary, and to mitigate accidents. Pursuant to 10 CFR 50.36(c)(1)(ii)(A), if it is determined that an automatic protective device for a variable on which a safety limit has been placed (i.e., limiting safety system setting) does not function as required, appropriate action is taken to ensure the abnormal situation is corrected before a safety limit is exceeded, which may include shutting down the reactor. The CEG instrument setpoint methodology calculates trip setpoints using methods consistent with the guidance provided in NRC Regulatory Guide (RG) 1.105 and ANSI/ISA Standard 67.04. Additionally, pre-defined limits (i.e., as-found limits and as-left limits) are determined for each instrument consistent with the guidance provided in RG 1.105 and ANSI/ISA–RP67.04.

Discussion of Changes, TS 3/4.3.5, Loss of Power Instrumentation
Page 2

The removal of these details from the TS is acceptable because this type of information is not necessary to provide adequate protection of public health and safety. Proposed TS 3.3.5 retains the Allowable Values associated with the Loss of Power Instrumentation, which are designated as the operability limits for the required Trip Functions. These types of procedural details will be adequately controlled under the requirements of 10 CFR 50.59, which ensures changes are properly evaluated. In addition, the proposed change is consistent with the NRC's Standard Technical Specifications in NUREG-1433, "Standard Technical Specifications, General Electric BWR/4 Plants."

D03

Current TS 3.3.3, "Emergency Core Cooling System Actuation Instrumentation," Table 3.3.3-1, for Trip function 5, "Loss of Power," includes columns for "Total No. of Channels," "Channels to Trip," and "Minimum Channels Operable." Each of the columns contain the same values. As an editorial change, the "Total No. of Channels" column and "Channels to Trip" column are deleted and the "Minimum Channels Operable" column is renamed "Minimum Operable Channels." The existing footnote (f), which states, "A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2," is moved from the "Total No. of Channels" column to the "Minimum Operable Channels" column and retained. Existing Table 3.3.3.1 Actions 36 and 37, moved to Actions a and b, are revised to refer to "Minimum Operable Channels" instead of "Total No. of Channels."

The proposed change is acceptable because the elimination of duplicated requirements and changes to column headings do not result in any technical changes to the requirements.

D04

Current TS 3.3.3, SR 4.3.3.3 requires demonstration of the ECCS Response Time for each trip function in Table 3.3.3-3. The Table 3.3.3-3 entry for "Loss of Power," is "N.A.," indicating that an ECCS Response Time demonstration is not required. These requirements are not included in the new Specification 3.3.5.

The proposed change is acceptable because the elimination of information that is not applicable does not result in any technical changes to the requirements.

Unit 1

Proposed Technical Specifications

3/4.3 INSTRUMENTATION

3/4.3.5 LOSS OF POWER INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3, Function 5

3.3.5 The Loss of Power instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE.

Table 3.3.3-1, Function 5

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

Table 3.3.3-1, Action 36
Table 3.3.3-1, Action 37

ACTION:

a. With the number of OPERABLE Loss of Voltage channels less than the Minimum Operable 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.

b. With the number of OPERABLE Degraded Voltage channels one less than the Minimum Operable Channels, place the inoperable device in the bypassed condition subject to the following conditions:

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable. 127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

SURVEILLANCE REQUIREMENTS

4.3.3.1 4.3.5.1 The Loss of Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST at the frequencies specified in the Surveillance Frequency Control Program. The Loss of Voltage Relay 127-11X is not field setable.

4.3.3.1 4.3.5.2 The Degraded Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

4.3.3.2 4.3.5.3 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all Loss of Power channels shall be performed in accordance with the Surveillance Frequency Control Program.

Table 3.3.3-1, Note **

** Required OPERABLE when ESF equipment is required to be OPERABLE.

CTS
Table 3.3.3-1
Function 5.1
Function 5.2

TABLE 3.3.5-1

LOSS OF POWER INSTRUMENTATION

LOSS OF POWER		MINIMUM OPERABLE CHANNELS[(a)]
1.	4.16 Kv Emergency Bus Under-voltage (Loss of Voltage)	1/bus
2.	4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	1/source/bus

Note (f)

(a) A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2.

CTS

Table 3.3.3-2

TABLE 3.3.5-2

LOSS OF POWER ALLOWABLE VALUES

TRIP FUNCTION	RELAY		ALLOWABLE VALUE
Function 5.a			
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	RELAY 127-11X		NA
Function 5.b			
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	RELAY 127-11X0X	a.	4.16 kV Basis 2905 ± 145 volts
	102-11X0X	b.	120 V Basis 83 ± 4 volts
		c.	≤ 1.5 second time delay
	127Y-11X0X**	a.	4.16 kV Basis 3640 ± 182 volts
	127Y-1-11X0X	b.	120 V Basis 104 ± 5.2 volts
		c.	≤ 60 second time delay
	127Z-11X0X	a.	4.16 kV Basis 3910 ± 19 volts
	162Y-11X0X	b.	120 V Basis 111.7 ± 0.5 volts
		c.	≤ 11 second time delay
	127Z-11X0X	a.	4.16 kV Basis 3910 ± 19 volts
	162Z-11X0X	b.	120 V Basis 111.7 ± 0.5 volts
		c.	≤ 64 second time delay

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

Table 3.3.3-2,
Note **

Unit 2

Proposed Technical Specifications

3/4.3 INSTRUMENTATION

3/4.3.5 LOSS OF POWER INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.5 The Loss of Power instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE.

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

ACTION:

a. With the number of OPERABLE Loss of Voltage channels less than the Minimum Operable 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.

b. With the number of OPERABLE Degraded Voltage channels one less than the Minimum Operable Channels, place the inoperable device in the bypassed condition subject to the following conditions:

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable. 127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

SURVEILLANCE REQUIREMENTS

4.3.5.1 The Loss of Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST at the frequencies specified in the Surveillance Frequency Control Program. The Loss of Voltage Relay 127-11X is not field setable.

4.3.5.2 The Degraded Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

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

** Required OPERABLE when ESF equipment is required to be OPERABLE.

TABLE 3.3.5-1

LOSS OF POWER INSTRUMENTATION

LOSS OF POWER	MINIMUM OPERABLE CHANNELS[(a)]
1. 4.16 Kv Emergency Bus Under-voltage (Loss of Voltage)	1/bus
2. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	1/source/bus

(a) A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2.

TABLE 3.3.5-2

LOSS OF POWER ALLOWABLE VALUES

TRIP FUNCTION	RELAY		ALLOWABLE VALUE
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X		NA
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	127-11X0X	a.	4.16 kV Basis 2905 ± 145 volts
	102-11X0X	b.	120 V Basis 83 ± 4 volts
		c.	≤ 1.5 second time delay
	127Y-11X0X**	a.	4.16 kV Basis 3640 ± 182 volts
	127Y-1-11X0X	b.	120 V Basis 104 ± 5.2 volts
		c.	≤ 60 second time delay
	127Z-11X0X	a.	4.16 kV Basis 3910 ± 19 volts
	162Y-11X0X	b.	120 V Basis 111.7 ± 0.5 volts
		c.	≤ 11 second time delay
	127Z-11X0X	a.	4.16 kV Basis 3910 ± 19 volts
	162Z-11X0X	b.	120 V Basis 111.7 ± 0.5 volts
		c.	≤ 64 second time delay

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

Unit 1

Revised Technical Specifications Bases (For Information Only)

3/4.3.3 EMERGENCY CORE COOLING ACTUATION INSTRUMENTATION (Continued)

3.3.1 Bases

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Insert 1

~~Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.~~

~~Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.~~

3/4.3.3.A REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

3.3.3 Bases

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close

3/4.3.5 LOSS OF POWER INSTRUMENTATION

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

Unit 2

Revised Technical Specifications Bases (For Information Only)

INSTRUCTION

PTS Bases BASES

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION (Continued)

3/4.3.1 Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

Insert 1

~~Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.~~

~~Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.~~

3/4.3.3.A REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

3/4.3.3 Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation

3/4.3.5 LOSS OF POWER INSTRUMENTATION

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X0X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X0X relay.

Specification 3/4.5.1, ECCS - Operating

Unit 1

Current Technical Specifications Markup

PTS 3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 3.5.1 The emergency core cooling systems shall be OPERABLE with:

a. The core spray system (CSS) consisting of two subsystems with each subsystem comprised of:

1. Two OPERABLE CSS pumps, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

b. The low pressure coolant injection (LPCI) system of the residual heat removal system consisting of four subsystems with each subsystem comprised of:

1. One OPERABLE LPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

c. The high pressure coolant injection (HPCI) system consisting of:

1. One OPERABLE HPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

consisting of two subsystems controlling

d. The automatic depressurization system (ADS) ~~with~~ at least five OPERABLE ADS valves. D01

APPLICABILITY: OPERATIONAL CONDITION 1, 2* ** #, and 3* ** ##.

*The HPCI system is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

**The ADS is not required to be OPERABLE when the reactor steam dome pressure is less that or equal to 100 psig.

#See Special Test Exception 3.10.6.

##Two LPCI subsystems of the RHR system may be inoperable in that they are aligned in the shutdown cooling mode when reactor vessel pressure is less than the RHR Shutdown cooling permissive setpoint.

PTS EMERGENCY CORE COOLING SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

3.5.1 ACTION: (Continued)

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 in accordance with the Risk Informed Completion Time Program, 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 in accordance with the Risk Informed Completion Time Program, 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 in accordance with the Risk Informed Completion Time Program, 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. D01

Insert 1

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.~~ D02

~~f.~~ ~~DELETED~~

Specification 3/4.5.1

Insert 1

3. With either ADS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within:
   a. 7 days provided that the HPCI and RCIC Systems are OPERABLE, or
   b. 72 hours.

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

4. With both ADS subsystems inoperable, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the following 24 hours.

PTS

EMERGENCY CORE COOLING SYSTEMS

SURVEILLANCE REQUIREMENTS

4.5.1 4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system:

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

b) 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.***

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-182 A, B) are closed with power removed from the valve operators.

3. For the HPCI system, verifying that the HPCI pump flow controller is in the correct position.

~~4. For the CSS and LPCI system, performance of a CHANNEL FUNCTIONAL TEST of the injection header ΔP instrumentation.~~ D02

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. Each CSS pump in each subsystem develops a flow of at least 3175 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1040 psig plus head and line losses when steam is being supplied to the turbine at 1040, +13, -120 psig.**

c. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

* Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

** 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 200 psig within the following 72 hours.

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

PTS EMERGENCY CORE COOLING SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

4.5.1

2. For the HPCI system, verifying that:

a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of ≥200 psig plus head and line losses, when steam is being supplied to the turbine at 200 + 15, - 0 psig.**

b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber water level - high signal.

~~3. Performing a CHANNEL CALIBRATION of the CSS, LPCI, and HPCI system discharge line "keep filled" alarm instrumentation.~~ D03

~~4. Performing a CHANNEL CALIBRATION of the CSS header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 4.4 psid.~~ D02

~~5. Performing a CHANNEL CALIBRATION of the LPCI header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 3.0 psid.~~ D02

d. For the ADS:

1. In accordance with the Surveillance Frequency Control Program, verify ADS accumulator gas supply header pressure is ≥90 psig.

2. In accordance with the Surveillance Frequency Control Program:

a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

b) Verify that when tested pursuant to Specification 4.0.5 that each ADS valve is capable of being opened.

~~c) DELETED~~

** 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 HPCI OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

Unit 2

Current Technical Specifications Markup

PTS

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1

3.5.1 The emergency core cooling systems shall be OPERABLE with:

a. The core spray system (CSS) consisting of two subsystems with each subsystem comprised of:

1. Two OPERABLE CSS pumps, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

b. The low pressure coolant injection (LPCI) system of the residual heat removal system consisting of four subsystems with each subsystem comprised of:

1. One OPERABLE LPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

c. The high pressure coolant injection (HPCI) system consisting of:

1. One OPERABLE HPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

consisting of two subsystems controlling

d. The automatic depressurization system (ADS) ~~with~~ at least five OPERABLE ADS valves. D01

APPLICABILITY: OPERATIONAL CONDITION 1, 2* ** #, and 3* ** ##.

---

*The HPCI system is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

**The ADS is not required to be OPERABLE when the reactor steam dome pressure is less that or equal to 100 psig.

#See Special Test Exception 3.10.6.

##Two LPCI subsystems of the RHR system may be inoperable in that they are aligned in the shutdown cooling mode when reactor vessel pressure is less than the RHR Shutdown cooling permissive setpoint.

PTS

EMERGENCY CORE COOLING SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

3.5.1

ACTION: (Continued)

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 in accordance with the Risk Informed Completion Time Program, 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 in accordance with the Risk Informed Completion Time Program, 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 in accordance with the Risk Informed Completion Time Program, 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. D01

Insert 1

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.~~ D02

~~f.~~ ~~DELETED~~

Specification 3/4.5.1

Insert 1

3. With either ADS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within:
    a. 7 days provided that the HPCI and RCIC Systems are OPERABLE, or
    b. 72 hours.

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

4. With both ADS subsystems inoperable, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the following 24 hours.

EMERGENCY CORE COOLING SYSTEMS

4.5.1 SURVEILLANCE REQUIREMENTS

4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system:

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

b) 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.***

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-282 A, B) are closed with power removed from the valve operators.

3. For the HPCI system, verifying that the HPCI pump flow controller is in the correct position.

~~4. For the CSS and LPCI system, performance of a CHANNEL FUNCTIONAL TEST of the injection header ΔP instrumentation.~~ D02

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. Each CSS pump in each subsystem develops a flow of at least 3175 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of = 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1040 psig plus head and line losses when steam is being supplied to the turbine at 1040, +13, -120 psig.**

c. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. **** Actual injection of coolant into the reactor vessel may be excluded from this test.

---

* Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

** 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 200 psig within the following 72-hours.

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

**** Except for valves that are locked, sealed, or otherwise secured in the actuated position.

SURVEILLANCE REQUIREMENTS (Continued)

4.5.1

2. For the HPCI system, verifying that:

   a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of ≥ 200 psig plus head and line losses, when steam is being supplied to the turbine at 200 + 15, - 0 psig.**

   b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber water level - high signal.

~~3. Performing a CHANNEL CALIBRATION of the CSS, LPCI, and HPCI system discharge line "keep filled" alarm instrumentation~~. D03

~~4. Performing a CHANNEL CALIBRATION of the CSS header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 4.4 psid~~. D02

~~5. Performing a CHANNEL CALIBRATION of the LPCI header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 3.0 psid~~. D02

d. For the ADS:

1. In accordance with the Surveillance Frequency Control Program, verify ADS accumulator gas supply header pressure is ≥90 psig.

2. In accordance with the Surveillance Frequency Control Program:

   a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

   b) Verify that when tested pursuant to Specification 4.0.5 that each ADS valve is capable of being opened.

   ~~c) DELETED~~

** 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 HPCI OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

Discussion of Changes

Discussion of Changes

Technical Specification 3/4.5.1
ECCS - Operating

D01

Current TS 3.5.1, "ECCS - Operating," is revised to reflect the revised plant design for actuation of the Automatic Depressurization System (ADS). Under the revised design, the ADS actuation is provided by two PPS divisions. It is clearer to describe this relationship and provide the appropriate Actions in TS 3.5.1 than in TS 3.3.2. Current TS LCO 3.5.1.d is revised from, "The automatic depressurization system (ADS) with at least five OPERABLE ADS valves," to "The automatic depressurization system (ADS) consisting of two subsystems controlling at least five OPERABLE ADS valves."

New Actions d.3 and d.4 are added providing the appropriate mitigating measures for one or two inoperable subsystems, respectively. Proposed Action d.3 states that with either ADS subsystem inoperable, to restore the inoperable subsystem to operable statue within 7 days if both HPCI and RCIC are operable, or within 72 hours (i.e., if either HPCI or RCIC are inoperable). The option to utilize a RICT is not retained at this time. If the inoperable subsystem is not restored within the specified time, the plant must be in at least Hot Shutdown within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the following 24 hours. This is equivalent to the existing requirements in current TS 3.3.3, "ECCS Actuation Instrumentation," Action c. Proposed Action d.4 states that with both ADS subsystems inoperable, the plant must be in at least Hot Shutdown within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the following 24 hours. This is equivalent to current TS 3.3.3, Action d. The proposed change is acceptable because the current requirements have been retained and only relocated to another specification.

D02

Current TS 3.5.1 contains SRs and Actions related to the Core Spray System (CSS) and Low Pressure Coolant Injection (LPCI) differential pressure (ΔP) instrumentation. The SRs are 4.5.1.a.4 (Channel Functional Test), 4.5.1.c.4 (CSS Channel Calibration), and 4.5.1.c.5 (LPCI Channel Calibration). The Action is Action e. The SRs and Action are removed in the proposed TS. These instruments are alarm-only functions that alert the operator to leakage from the CSS and LPCI systems.

CEG evaluated alarm-only indications for inclusion in the new control room design and, although the alarm was chosen to be maintained due to the defense-in-depth, it is not critical to either identification or response in an accident or transient condition, and is not needed to satisfy the LCO. As such, the alarm is being relocated from the TS. Relocation of these requirements from the TS to licensee procedures is consistent with the standard TS (NUREG-1433). As stated in NEDC-31681, "Improved BWR Technical Specifications," Volume 4, April 1989:

> "CSS (and/or LPCI) header integrity is required by definition of operability. The header(s) Δp instrumentation channels provide an alarm and indication only. Alarm only instruments (except those required by Reg. Guide 1.97 and found in LCO 3.3.3.1) are not included in the Improved BWR TS. They represent part of routine operational monitoring and are applicable to plant specific controls. They do not represent instruments which are required to support operability."

The NRC accepted this justification and the CSS and LPCI ΔP instruments were not included in NUREG-1433. This change is acceptable because the CSS and LPCI ΔP instruments are not instruments required to satisfy the LCO and can be placed under licensee control.

D03

Current TS 3.5.1, SR 4.5.1.c.3 requires the performance of a Channel Calibration of the CSS, LPCI, and HPCI System discharge line "keep filled" alarm instrumentation. In the proposed TS, this alarm function is removed from the TS and placed under licensee control.

CEG evaluated alarm-only indications for inclusion in the new control room design and, although the alarm was chosen to be maintained due to the defense-in-depth, it is not critical to either identification or response in an accident or transient condition, and is not needed to satisfy the LCO. As such, the alarm is being relocated from the TS.

Current SR 4.5.1.a.1.a, which is unaffected by the proposed change, requires verification that locations susceptible to gas accumulation are sufficiently filled with water. The "keep filled" system and associated alarm are a method to ensure the system is sufficiently filled with water, but they are not required and the surveillance can be satisfied without them. There are no equivalent requirements in the standard TS (NUREG-1433). This change is acceptable because the "keep filled" system and alarm are not required to satisfy the LCO and can be placed under licensee control.

Unit 1

Proposed Technical Specifications

CTS

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 3.5.1 The emergency core cooling systems shall be OPERABLE with:

a. The core spray system (CSS) consisting of two subsystems with each subsystem comprised of:

1. Two OPERABLE CSS pumps, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

b. The low pressure coolant injection (LPCI) system of the residual heat removal system consisting of four subsystems with each subsystem comprised of:

1. One OPERABLE LPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

c. The high pressure coolant injection (HPCI) system consisting of:

1. One OPERABLE HPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

d. The automatic depressurization system (ADS) consisting of two subsystems controlling at least five OPERABLE ADS valves.

APPLICABILITY: OPERATIONAL CONDITION 1, 2* ** #, and 3* ** ##.

*The HPCI system is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

**The ADS is not required to be OPERABLE when the reactor steam dome pressure is less that or equal to 100 psig.

#See Special Test Exception 3.10.6.

##Two LPCI subsystems of the RHR system may be inoperable in that they are aligned in the shutdown cooling mode when reactor vessel pressure is less than the RHR Shutdown cooling permissive setpoint.

No changes on this page.

3.5.1 LIMITING CONDITION FOR OPERATION (Continued)

ACTION:

a. For the core spray system:
   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 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.

   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 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 three LPCI subsystems inoperable, provided that both CSS subsystems are OPERABLE, restore at least two LPCI subsystems 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.

   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.*

*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.

CTS EMERGENCY CORE COOLING SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

3.5.1 ACTION: (Continued)

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

3. With either ADS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within:
   a. 7 days provided that the HPCI and RCIC Systems are OPERABLE, or
   b. 72 hours.

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

4. With both ADS subsystems inoperable, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the following 24 hours.

CTS

EMERGENCY CORE COOLING SYSTEMS

SURVEILLANCE REQUIREMENTS

4.5.1 4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system:

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

b) 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.***

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-182 A, B) are closed with power removed from the valve operators.

3. For the HPCI system, verifying that the HPCI pump flow controller is in the correct position.

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. Each CSS pump in each subsystem develops a flow of at least 3175 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1040 psig plus head and line losses when steam is being supplied to the turbine at 1040, +13, -120 psig.**

c. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

---

* Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

** 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 200 psig within the following 72 hours.

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

CTS EMERGENCY CORE COOLING SYSTEMS

4.5.1 SURVEILLANCE REQUIREMENTS (Continued)

2. For the HPCI system, verifying that:

a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure
of ≥ 200 psig plus head and line losses, when steam is being
supplied to the turbine at 200 + 15, - 0 psig.**

b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber water level - high signal.

d. For the ADS:

1. In accordance with the Surveillance Frequency Control Program, verify ADS accumulator gas supply header pressure is ≥90 psig.

2. In accordance with the Surveillance Frequency Control Program:

a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

b) Verify that when tested pursuant to Specification 4.0.5 that each ADS valve is capable of being opened.

** 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 HPCI OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

Unit 2

Proposed Technical Specifications

See Unit 1 Markup for CTS References

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 The emergency core cooling systems shall be OPERABLE with:

a. The core spray system (CSS) consisting of two subsystems with each subsystem comprised of:

1. Two OPERABLE CSS pumps, and
2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

b. The low pressure coolant injection (LPCI) system of the residual heat removal system consisting of four subsystems with each subsystem comprised of:

1. One OPERABLE LPCI pump, and
2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

c. The high pressure coolant injection (HPCI) system consisting of:

1. One OPERABLE HPCI pump, and
2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

d. The automatic depressurization system (ADS) consisting of two subsystems controlling at least five OPERABLE ADS valves.

APPLICABILITY: OPERATIONAL CONDITION 1, 2* ** #, and 3* ** ##.

*The HPCI system is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

**The ADS is not required to be OPERABLE when the reactor steam dome pressure is less that or equal to 100 psig.

#See Special Test Exception 3.10.6.

##Two LPCI subsystems of the RHR system may be inoperable in that they are aligned in the shutdown cooling mode when reactor vessel pressure is less than the RHR Shutdown cooling permissive setpoint.

No changes on this page.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION:

a. For the core spray system:

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 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.

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 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 three LPCI subsystems inoperable, provided that both CSS subsystems are OPERABLE, restore at least two LPCI subsystems 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.

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.*

*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.

EMERGENCY CORE COOLING SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

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

3. With either ADS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within:
   a. 7 days provided that the HPCI and RCIC Systems are OPERABLE, or
   b. 72 hours.

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

4. With both ADS subsystems inoperable, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the following 24 hours.

EMERGENCY CORE COOLING SYSTEMS

SURVEILLANCE REQUIREMENTS

4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system:

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

b) 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.***

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-182 A, B) are closed with power removed from the valve operators.

3. For the HPCI system, verifying that the HPCI pump flow controller is in the correct position.

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. Each CSS pump in each subsystem develops a flow of at least 3175 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1040 psig plus head and line losses when steam is being supplied to the turbine at 1040, +13, -120 psig.**

c. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

---

* Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

** 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 200 psig within the following 72 hours.

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

2. For the HPCI system, verifying that:

   a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of ≥ 200 psig plus head and line losses, when steam is being supplied to the turbine at 200 + 15, - 0 psig.**

   b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber water level - high signal.

d. For the ADS:

1. In accordance with the Surveillance Frequency Control Program, verify ADS accumulator gas supply header pressure is ≥90 psig.

2. In accordance with the Surveillance Frequency Control Program:

   a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

   b) Verify that when tested pursuant to Specification 4.0.5 that each ADS valve is capable of being opened.

** 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 HPCI OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

Unit 1

Revised Technical Specifications Bases (For Information Only)

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.

3/4.5.1 Bases Insert 1

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.

The ADS is composed of two redundant logic and power subsystems acting upon the same five valves. Division 1 PPS and Division 3 PPS provide for automatic and manual actuation to redundant solenoids on each SRV pneumatic pilot valve operator. These subsystems are electrically and physically separated, with either subsystem capable of accomplishing the safety related function. Therefore, a loss of either Division 1 or Division 3 does not render the ADS valves inoperable.

Unit 2

Revised Technical Specifications Bases (For Information Only)

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) automa-tically 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 claddi temperature to less than 2200°F. ADS is conserva-tively required to be OPERABLE whenever reactor vessel pressure exceeds 10 psig. This pressure is substantially below that for which the low pressure core cool-ing systems can provide adequate core cooling for events requiring ADS.

3/4.5.1 Bases Insert 1

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.

The ADS is composed of two redundant logic and power subsystems acting upon the same five valves. Division 1 PPS and Division 3 PPS provide for automatic and manual actuation to redundant solenoids on each SRV pneumatic pilot valve operator. These subsystems are electrically and physically separated, with either subsystem capable of accomplishing the safety related function. Therefore, a loss of either Division 1 or Division 3 does not render the ADS valves inoperable.

Specification 3/4.7.9, Turbine Enclosure – Main Steam Line Tunnel Temperature

Unit 1

Current Technical Specifications Markup

3/4.7.9 TURBINE ENCLOSURE - MAIN STEAM LINE TUNNEL TEMPERATURE

3/4.3 INSTRUMENTATION

~~3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

D01

LIMITING CONDITION FOR OPERATION

3.7.9 ~~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.~~

3.7.9 The Turbine Enclosure Main Steam Line Tunnel temperature shall be ≤ 175°F

APPLICABILITY: ~~As shown in Table 3.3.1-1.~~ OPERATIONAL CONDITIONS 1, 2, and 3

ACTION:

~~Note: Separate condition entry is allowed for each channel.~~

~~Note: When Functional Unit 2.b and 2.c channels are inoperable due to the calculated power exceeding the APRM output by more than 2% of RATED THERMAL POWER while operating at ≥ 25% of RATED THERMAL POWER, entry into the associated Actions may be delayed up to 2 hours.~~

Insert 1

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

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

~~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.~~

~~*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.~~

Specification 3/4.7.9

Insert 1

With the Turbine Enclosure Main Steam Line tunnel temperature not within the limits, immediately and at least once per 12 hours thereafter verify there is no main steam leak in the Main Steam Line tunnel. Otherwise, be in HOT SHUTDOWN within 12 hours and COLD SHUTDOWN with the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.5.1 The Turbine Enclosure Main Steam Line tunnel temperature shall be determined to be within the limit in accordance with the Surveillance Frequency Control Program.

PTS

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low-Level 2	B	2	1, 2, 3	21
2) Low, Low, Low-Level 1	C	2	1, 2, 3	21
b. DELETED	DELETED	DELETED	DELETED	DELETED
c. Main Steam Line Pressure - Low	P	2	1	22
d. Main Steam Line Flow - High	E	2/line	1, 2, 3	20
e. Condenser Vacuum - Low	Q	2	1, 2**, 3**	21
f. Outboard MSIV Room Temperature - High	F(f)	2	1, 2, 3	21
~~g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High~~	~~F(f)~~	~~14~~	~~1, 2, 3~~	~~21~~
h. Manual Initiation	NA	2	1, 2, 3	24
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level Low - Level 3	A	2	1, 2, 3	23
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	V	2	1, 2, 3	23
c. Manual Initiation	NA	1	1, 2, 3	24

3.3.1

3.3.1

D01

PTS

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level		
1) Low, Low - Level 2	≥ - 38 inches*	≥ - 45 inches
2) Low, Low, Low - Level 1	≥ - 129 inches*	≥ - 136 inches
3.3.1` b. DELETED	DELETED	DELETED
c. Main Steam Line Pressure - Low	≥ 840 psig	≥ 821 psig
d. Main Steam Line Flow - High	≤ 122.1 psid	≤ 123 psid
e. Condenser Vacuum - Low	10.5 psia	≥10.1 psia/≤ 10.9 psia
f. Outboard MSIV Room Temperature - High	≤ 192°F	≤ 200°F
~~g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High~~	~~≤ 165°F~~	~~≤ 175°F~~ D01
h. Manual Initiation	N.A.	N.A.
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		
3.3.1 a. Reactor Vessel Water Level Low - Level 3	≥ 12.5 inches*	≥ 11.0 inches
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	≤ 75 psig	≤ 95 psig
c. Manual Initiation	N.A.	N.A.

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION			RESPONSE TIME (Seconds)#
1.	MAIN STEAM LINE ISOLATION		
	a.	Reactor Vessel Water Level	
		1) Low, Low - Level 2	N.A.
		2) Low, Low, Low - Level 1	≤1.0###*
	b.	DELETED	DELETED
	c.	Main Steam Line Pressure - Low	≤1.0###*
	d.	Main Steam Line Flow - High	≤1.0###*
	e.	Condenser Vacuum - Low	N.A.
	f.	Outboard MSIV Room Temperature - High	N.A.
	~~g.~~	~~Turbine Enclosure - Main Steam Line Tunnel Temperature - High~~	~~N.A.~~
	h.	Manual Initiation	N.A.
2.	RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		
	a.	Reactor Vessel Water Level Low - Level 3	N.A.
	b.	Reactor Vessel (RHR Cut-In Permissive) Pressure - High	N.A.
	c.	Manual Initiation	N.A.
3.	REACTOR WATER CLEANUP SYSTEM ISOLATION		
	a.	RWCS Δ Flow - High	N.A.##
	b.	RWCS Area Temperature - High	N.A.
	c.	RWCS Area Ventilation Δ Temperature - High	N.A.
	d.	SLCS Initiation	N.A.
	e.	Reactor Vessel Water Level - Low, Low - Level 2	N.A.
	f.	Manual Initiation	N.A.

3.3.2

3.3.2

D01

TABLE 4.3.2.1-1

PTS

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(a)	CHANNEL FUNCTIONAL TEST(a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low, Level 2				1, 2, 3
2) Low, Low, Low - Level 1				1, 2, 3
b. DELETED				
3.3.1 c. Main Steam Line Pressure - Low				1
d. Main Steam Line Flow - High				1, 2, 3
e. Condenser Vacuum - Low				1, 2**, 3**
f. Outboard MSIV Room Temperature - High				1, 2, 3
~~g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High~~				~~1, 2, 3~~ D01
h. Manual Initiation	N.A.		N.A.	1. 2, 3
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
3.3.1 a. Reactor Vessel Water Level~~##~~ Low - Level 3				1, 2, 3
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High				1, 2, 3
c. Manual Initiation	N.A.		N.A.	1, 2, 3

Unit 2

Current Technical Specifications Markup

PTS

D01

3/4.7.9 TURBINE ENCLOSURE - MAIN STEAM LINE TUNNEL TEMPERATURE

3/4.3 INSTRUMENTATION

~~3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION~~

LIMITING CONDITION FOR OPERATION

3.7.9 ~~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.~~

3.7.9 The Turbine Enclosure Main Steam Line Tunnel temperature shall be ≤ 175°F

APPLICABILITY: ~~As shown in Table 3.3.1-1.~~ OPERATIONAL CONDITIONS 1, 2, and 3

ACTION:

~~Note: Separate condition entry is allowed for each channel.~~

Insert 1

~~Note: When Functional Unit 2.b and 2.c channels are inoperable due the calculated power exceeding the APRM output by more than 2% of RATED THERMAL POWER while operating at ≥ 25% of RATED THERMAL POWER, entry into the associated Actions may be delayed up to 2 hours.~~

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

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

~~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.~~

~~* 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.~~

Specification 3/4.7.9

Insert 1

With the Turbine Enclosure Main Steam Line tunnel temperature not within the limits, immediately and at least once per 12 hours thereafter verify there is no main steam leak in the Main Steam Line tunnel. Otherwise, be in HOT SHUTDOWN within 12 hours and COLD SHUTDOWN with the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.5.1 The Turbine Enclosure Main Steam Line tunnel temperature shall be determined to be within the limit in accordance with the Surveillance Frequency Control Program.

PTS

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	ISOLATION SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level				
1) Low, Low-Level 2	B	2	1, 2, 3	21
2) Low, Low, Low-Level 1	C	2	1, 2, 3	21
b. DELETED	DELETED	DELETED	DELETED	DELETED
c. Main Steam Line Pressure - Low	P	2	1	22
d. Main Steam Line Flow - High	E	2/line	1, 2, 3	20
e. Condenser Vacuum - Low	Q	2	1, 2**, 3**	21
f. Outboard MSIV Room Temperature - High	F(f)	2	1, 2, 3	21
~~g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High~~	~~F(f)~~	~~14~~	~~1, 2, 3~~	~~21~~
h. Manual Initiation	NA	2	1, 2, 3	24
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
a. Reactor Vessel Water Level Low - Level 3	A	2	1, 2, 3	23
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	V	2	1, 2, 3	23
c. Manual Initiation	NA	1	1, 2, 3	24

3.3.1

3.3.1

D01

PTS

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level		
1) Low, Low - Level 2	≥ - 38 inches*	≥ - 45 inches
2) Low, Low, Low - Level 1	≥ - 129 inches*	≥ - 136 inches
b. DELETED	DELETED	DELETED
3.3.1 c. Main Steam Line Pressure - Low	≥ 840 psig	≥ 821 psig
d. Main Steam Line Flow - High	≤ 122.1 psid	≤ 123 psid
e. Condenser Vacuum - Low	10.5 psia	≥10.1 psia/≤ 10.9 psia
f. Outboard MSIV Room Temperature - High	≤ 192°F	≤ 200°F
~~g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High~~	~~≤ 165°F~~	~~≤ 175°F~~ D01
h. Manual Initiation	N.A.	N.A.
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		
3.3.1 a. Reactor Vessel Water Level Low - Level 3	≥ 12.5 inches*	≥ 11.0 inches
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	≤ 75 psig	≤ 95 psig
c. Manual Initiation	N.A.	N.A.

PTS

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
1. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level	
1) Low, Low - Level 2	N.A.
2) Low, Low, Low - Level 1	≤1.0###*
b. DELETED	DELETED
c. Main Steam Line Pressure - Low	≤1.0###*
3.3.2 d. Main Steam Line Flow - High	≤1.0###*
e. Condenser Vacuum - Low	N.A.
f. Outboard MSIV Room Temperature - High	N.A.
~~g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High~~	~~N.A.~~ D01
h. Manual Initiation	N.A.
2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
a. Reactor Vessel Water Level Low - Level 3	N.A.
b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High	N.A.
c. Manual Initiation	N.A.
3.3.2 3. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. RWCS Δ Flow - High	N.A.##
b. RWCS Area Temperature - High	N.A.
c. RWCS Area Ventilation Δ Temperature - High	N.A.
d. SLCS Initiation	N.A.
e. Reactor Vessel Water Level - Low, Low - Level 2	N.A.
f. Manual Initiation	N.A.

TABLE 4.3.2.1-1

PTS

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	TRIP FUNCTION	CHANNEL CHECK (a)	CHANNEL FUNCTIONAL TEST (a)	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
	1. MAIN STEAM LINE ISOLATION				
	a. Reactor Vessel Water Level				
	1) Low, Low, Level 2				1, 2, 3
	2) Low, Low, Low - Level 1				1, 2, 3
	b. DELETED				DELETED
3.3.1	c. Main Steam Line Pressure - Low				1
	d. Main Steam Line Flow - High				1, 2, 3
	e. Condenser Vacuum - Low				1, 2**, 3**
	f. Outboard MSIV Room Temperature - High				1, 2, 3
	~~g. Turbine Enclosure - Main Steam Line Tunnel Temperature - High~~				~~1, 2, 3~~ D01
	h. Manual Initiation	N.A.		N.A.	1. 2, 3
	2. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION				
3.3.1	a. Reactor Vessel Water Level## Low - Level 3				1, 2, 3
	b. Reactor Vessel (RHR Cut-In Permissive) Pressure - High				1, 2, 3
	c. Manual Initiation	N.A.		N.A.	1, 2, 3

Discussion of Changes

Discussion of Changes

Technical Specification 3/4.7.9
Turbine Enclosure – Main Steam Line Tunnel Temperature

D01

The proposed change removes Function 1.g, "Turbine Enclosure - Main Steam Line Tunnel Temperature - High," and inserts the word "Deleted" in Table 3.3.2-1, Table 3.3.2-2, "Isolation Actuation Instrumentation Setpoints," Table 3.3.2-3, "Isolation Actuation Instrumentation Response Times," and Table 4.3.2.1-1, Isolation Actuation Instrumentation Surveillance Requirements." Deletion of Function 1.g does not require modification to any Actions or Surveillance Requirements.

The proposed change adds a new Specification 3.7.9, "Turbine Enclosure Main Steam Line Tunnel Temperature." The new LCO 3.7.9 requires the TS MSL Tunnel maximum temperature to be ≤ 175°F. The specification is applicable in Operational Conditions 1, 2, and 3, the same as existing Function 1.g. SR 3.7.9.1 requires verification that the TE MSL tunnel temperature is ≤ 175°F on a frequency controlled by the Surveillance Frequency Control Program (SFCP). The initial frequency will be 24 hours.

In the proposed TS, if the TE MSL tunnel maximum temperature exceeds 175°F, the Actions require immediate action to verify that no MSL leak exists, and periodic verification every 12 hours thereafter. If it cannot be verified that there is no MSL leakage or if the periodic verification is not performed, a plant shutdown is required. The plant must be in Operational Condition 3 (Hot Shutdown) within 12 hours and Operational Condition 4 (Cold Shutdown) with the following 24 hours.

The ambient temperature of the monitored TE MSL tunnel area can approach the isolation setpoint for reasons other than actual main steam leaks in the area, such as hot weather, reduced efficiency of the TE chillers, or instrument drift. If both TE MSL Tunnel Temperature - High trip systems were to initiate an isolation signal, a full Group 1 isolation and reactor trip would result. Group 1 isolation closes the MSIVs, resulting in a loss of heat sink, as well as rendering the main feedwater system unavailable for scram recovery. Such a shutdown would be considered a complicated scram.

The Turbine Enclosure - Main Steam Line Tunnel Temperature - High Function is not assumed to actuate in any accident analysis. The function is a surrogate for MSL leakage, which is an assumption in some accident analyses. However, creating the potential for a complicated reactor scram based on a surrogate indication, which may not be indicative of actual MSL leakage, is unnecessary. Replacing this automatic MSIV isolation requirement with a monitoring requirement and a manual shutdown if MSL leakage is detected will eliminate the risk of an unnecessary plant transient while still providing the appropriate remedial actions to ensure the plant is operating safely and within the assumed plant conditions.

Associated changes are proposed to the Unit 1 and Unit 2 TS Bases.

There are two purposes for the TE - MSL Tunnel Temperature - High MSIV Function:

1. Leak Before Break - The basis of this criterion is to isolate in order to prevent the leak from becoming a break. There was historical evidence that leaks would grow and become a break if not isolated. Early intergranular stress corrosion crack (IGSCC) propagation studies on stainless steel reactor coolant pressure boundary (RCPB) pipes in the containment showed that isolating a small leak provided assurance that the leak would not grow to a break. This same basis was conservatively applied to main steam carbon steel piping in the TE. However, later studies determined that cracks in main steam piping are not subject to IGSCC due to the lack of a corrosive environment. As a conservative action, the proposed TS 3.7.9 would require a plant shutdown if a leak is detected.
2. Dose Limits – The Loss of Coolant Accident (LOCA) analysis assumes a 35 gpm release of post-accident radioactive material into the TE from small MSL leaks. If an MSL leak larger than this limit was present and a LOCA occurred, the analyzed dose limits could be exceeded. A LOCA is not caused by a small MSL leak in the TE, and it is unnecessary to assume they occur simultaneously. The proposed TS 3.7.9 provides assurance that an MSL leak would be promptly identified and requires an immediate shutdown should a leak exist, eliminating a small MSL leak as a preexisting condition in the LOCA analysis.

Neither of these purposes require an automatic isolation of the MSLs on TE MSL tunnel high temperature or are dependent on an immediate reactor scram to assure plant safety. Given the purposes of the function, the consequences of an automatic reactor scram due to closure of the MSIVs is unwarranted.

As an alternative, the proposed TS 3.7.9 will ensure that an MSL steam leak in the TE MSL tunnel will be promptly detected and appropriate actions will be taken.

The proposed LCO 3.7.9 requires that the TE maximum temperature be ≤ 175°F. The limit of ≤ 175°F is based on detecting a leak equivalent to 35 gpm and is the allowable value of the current Function 1.g. The trip setpoint is relocated to licensee control, consistent with other monitoring functions, such as TS 3.6.1.7, "Drywell Average Air Temperature," TS 3.6.6.3, "Drywell and Suppression Chamber Oxygen Concentration," and Surveillance Requirement 4.7.2.1.a, control room air temperature.

The Applicability of LCO 3.7.9 is Operational Conditions 1, 2, and 3. In Operational Conditions 1, 2, and 3, a DBA could result in the release of radioactive material into the TE if there is a leak in the MSLs. In Operational Conditions 4 and 5, the probability and consequences of a DBA with fission product release into the TE are reduced because of the pressure and temperature limitations in these conditions.

Therefore, maintaining TE MSL tunnel temperature within limits is not required in Operational Conditions 4 or 5. The proposed Applicability is the same as the current Function 1.g.

The proposed Surveillance Requirement (SR) 3.7.9.1 requires verification that the TE MSL tunnel temperature is ≤175°F. The Frequency is controlled under the SFCP, and the initial frequency will be every 24 hours. As stated in SR 3.0.1, SRs must be met between performances of the Surveillance. If the TE MSL tunnel maximum temperature exceeds 175°F, indications in the main control room will alert operators to take action.

The TS 3.7.9 Actions apply if the TE MSL tunnel temperature is exceeded. It requires immediate action to determine if there is an MSL leak.

Indications of a small MSL leak in the TE MSL tunnel include, but are not limited to:

- An unexpected, sudden rise in tunnel air temperature,
- An unexpected increase in radiation monitor readings,
- An unexpected rise in TE sump levels,
- An unexpected decrease in plant electrical output, and
- Visual and sound indications.

TE tunnel temperature may be elevated due to reasons other than an MSL leak, such as hot weather, reduced TE area chiller capacity, and faulty temperature detectors. Verification will determine whether the elevated temperature is due to an MSL leak or another reason.

If the elevated temperature is determined to not be due to an MSL leak and as long as the TE MSL tunnel temperature exceeds 175°F, the Actions require verification every 12 hours that no MSL leak exists. The area monitored in the TE has elevated radiation levels and adverse environmental conditions. The 12-hour Completion Time balances the small likelihood of a MSL leak occurring since the last verification against the risks of exposing workers to the radiological and environmental conditions in order to perform the verification.

If an MSL leak is detected or if the periodic verification is not performed, the actions require a plant shutdown. The plant must be brought to least Operational Condition 3 (Hot Shutdown) within 12 hours and Operational Condition 4 (Cold Shutdown) with the following 24 hours. The proposed times are consistent with the requirements of similar specifications and are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

The following TS functions will continue to provide automatic MSL isolation on indication of a MSLB:

- Reactor Vessel Water Level - Low, Low - Level 2
- Reactor Vessel Water level - Low, Low, Low - Level 1
- Main Steam Line Pressure - Low
- Main Steam Line Flow - High
- Condenser Vacuum - Low
- Outboard MSIV Room Temperature - High

Environmental qualifications are not applied to equipment in the turbine enclosure, so removing the automatic isolation function and adding a manual shutdown requirement on high TE MSL tunnel temperature will have no effect on equipment qualification.

Although this requested elimination of an automatic isolation function is not risk-informed, CEG has developed risk insights related to the proposed change. The risk analysis was performed to demonstrate with reasonable assurance that eliminating the requirement for automatic MSL isolation on high TE MSL tunnel temperature is within the current risk acceptance guidelines in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis." The risk analysis was based on the ∆CDF and ∆LERF that results from assuming the TE steam line break high temperature function fails. This analysis does not assume operator action to detect a steam leak and assumes that unisolated breaks of any size result in core damage and large early release. In addition, this analysis does not credit the reduced change of spurious MSIV actuation from a fire. This analysis supports the acceptability of the proposed change.

Precedent

By letter dated October 13, 2021, SNC submitted a license amendment request for Edwin I. Hatch Nuclear Plant Unit Nos. 1 and 2 (Hatch) titled, "Request to Eliminate Automatic Main Steam Line Isolation on High Turbine Building Area Temperature" (Agencywide Documents Access and Management System (ADAMS) Accession No. ML21286A595). The amendment was approved on May 20, 2022 (ADAMS Accession No. ML22101A118). The proposed elimination of the LGS TE MSL Tunnel Temperature - High automatic isolation function is similar to the Hatch precedent.

The Hatch amendment is very similar to the proposed change in that the Hatch instrumentation function, "Turbine Building Area Temperature – High," served the same purpose as the LGS "Turbine Enclosure Main Steam Line Tunnel Temperature," Function. Both functions actuated the MSIVs on high temperature indications around the MSL. Both functions were intended to automatically shutdown the plant on small indications of MSL leakage. In both cases, actuation of the function would cause a complicated scram.

Differences between the Hatch amendment and the proposed change do not affect its use as precedent:

- Unlike the Hatch TS, the LGS TS are not based on NUREG-1433, "Standard Technical Specifications General Electric [Boiling-Water Reactor] BWR/4 Plants, Volume 1, Specifications," Revision 5.0 (ADAMS Accession No. ML21272A357). This affects the presentation of the requirements but not the content of the changes.

- The Hatch accident analysis assumes no MSL leakage prior to an accident while the LGS analysis assumes 35 gpm of leakage. The amount of leakage assumed in the LGS analysis is insignificant compared the MSL leakage assumed in the accident analysis and does not affect the acceptability of the change.

Unit 1

Proposed Technical Specifications

CTS

3/4.7 PLANT SYSTEMS

3/4.7.9 TURBINE ENCLOSURE MAIN STEAM LINE TUNNEL TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.3.2, Function 1.g

3.7.9 The Turbine Enclosure Main Steam Line tunnel temperature shall be ≤ 175°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3

ACTION:

With the Turbine Enclosure Main Steam Line tunnel temperature not within the limits, immediately and at least once per 12 hours thereafter verify there is no main steam leak in the Main Steam Line tunnel. Otherwise, be in HOT SHUTDOWN within 12 hours and COLD SHUTDOWN with the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.5.1 The Turbine Enclosure Main Steam Line tunnel temperature shall be determined to be within the limit in accordance with the Surveillance Frequency Control Program.

Unit 2

Proposed Technical Specifications

See Unit 1 Markup for CTS References

3/4.7 PLANT SYSTEMS

3/4.7.9 TURBINE ENCLOSURE MAIN STEAM LINE TUNNEL TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.7.9 The Turbine Enclosure Main Steam Line tunnel temperature shall be ≤ 175°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3

ACTION:

With the Turbine Enclosure Main Steam Line tunnel temperature not within the limits, immediately and at least once per 12 hours thereafter verify there is no main steam leak in the Main Steam Line tunnel. Otherwise, be in HOT SHUTDOWN within 12 hours and COLD SHUTDOWN with the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.5.1 The Turbine Enclosure Main Steam Line tunnel temperature shall be determined to be within the limit in accordance with the Surveillance Frequency Control Program.

Unit 1

Revised Technical Specifications Bases (For Information Only)

PLANT SYSTEMS

BASES

3/4.7.9 TURBINE ENCLOSURE MAIN STEAM LINE TUNNEL TEMPERATURE

The required OPERABILITY of the Turbine Enclosure Main Steam Line tunnel temperature monitors ensures that a Main Steam Line leak greater than that assumed in the accident analysis is detected. Should a temperature greater than the Allowable Value be detected, operators will determine if a Main Steam Line leak is present. Evidence of a Main Steam Line leak includes, but is not limited to:

- An unexpected, sudden rise in tunnel temperature,
- An unexpected increase in radiation monitor readings,
- An unexpected rise in TE sump levels,
- An unexpected decrease in plant electrical output, or
- Visual and sound indications.

If a Main Steam Leak is detected or the rise in Main Steam Line tunnel temperature cannot be attributed otherwise, a plant shutdown is required.

Unit 2

Revised Technical Specifications Bases (For Information Only)

PLANT SYSTEMS

BASES

3/4.7.9 TURBINE ENCLOSURE MAIN STEAM LINE TUNNEL TEMPERATURE

The required OPERABILITY of the Turbine Enclosure Main Steam Line tunnel temperature monitors ensures that a Main Steam Line leak greater than that assumed in the accident analysis is detected. Should a temperature greater than the Allowable Value be detected, operators will determine if a Main Steam Line leak is present. Evidence of a Main Steam Line leak includes, but is not limited to:

- An unexpected, sudden rise in tunnel temperature,
- An unexpected increase in radiation monitor readings,
- An unexpected rise in TE sump levels,
- An unexpected decrease in plant electrical output, or
- Visual and sound indications.

If a Main Steam Leak is detected or the rise in Main Steam Line tunnel temperature cannot be attributed otherwise, a plant shutdown is required.

Other Affected Specifications

Unit 1

Current Technical Specifications Markup

CTS

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

d. 25 gpm total leakage averaged over any 24-hour period.

e. 1 gpm leakage at a reactor coolant system pressure of 950 ±10 psig from any reactor coolant system pressure isolation valve.**

f. 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, isolate affected component, pipe, or vessel from the reactor coolant system by use of a closed manual valve, closed and de-activated automatic valve, blind flange, or check valve within 4 hours. Otherwise, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b, c and/or d above, reduce the leakage rate to within the limits within 4 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 reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one other closed manual, deactivated automatic, or check* valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

~~d. With one or more of the high/low pressure interface valve leakage pressure monitors inoperable, restore the inoperable monitor(s) to OPERABLE status within 7 days or verify the pressure to be less than the alarm setpoint at least once per 12 hours; restore the inoperable monitor(s) 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.~~ D02

d ~~e.~~ With any reactor coolant system leakage greater than the limit in f above, identify the source of leakage within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

---

* Which have been verified not to exceed the allowable leakage limit at the last refueling outage or after the last time the valve was disturbed, whichever is more recent.

** Pressure isolation valve leakage is not included in any other allowable operational leakage specified in Section 3.4.3.2.

REACTOR COOLANT SYSTEM

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment atmospheric gaseous radioactivity in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate in accordance with the Surveillance Frequency Control Program,

c. Monitoring the drywell unit coolers condensate flow rate in accordance with the Surveillance Frequency Control Program,

d. Monitoring the primary containment pressure in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system in accordance with the Surveillance Frequency Control Program, and

f. Monitoring the primary containment temperature in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. In accordance with the Surveillance Frequency Control Program, and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

~~4.4.3.2.3 The high/low pressure interface valve leakage pressure monitors shall be demonstrated OPERABLE with alarm setpoints set less than the specified allowable values by performance of a CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program~~. D02

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:

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 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 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.*

---

* 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.

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

1. Performing a system functional test which includes simulated automatic actuation and restart and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded.

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

~~4.~~ ~~Performing a CHANNEL CALIBRATION of the RCIC system discharge line "keep filled" level alarm instrumentation~~. D03

*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 tests. 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.

CTS

SPECIAL TEST EXCEPTIONS

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

LIMITING CONDITIONS FOR OPERATION

3.10.8 When conducting inservice leak or hydrostatic testing, the average reactor coolant temperature specified in Table 1.2 for OPERATIONAL CONDITION 4 may be increased to greater than 200°F, and operation considered not to be in OPERATIONAL CONDITION 3:

- For performance of an inservice leak or hydrostatic test,
- As a consequence of maintaining adequate pressure for an inservice leak or hydrostatic test, or
- As a consequence of maintaining adequate pressure for control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test,

provided the following OPERATIONAL CONDITION 3 Specifications are met:

a. ~~3.3.2 ISOLATION ACTUATION INSTRUMENTATION, Functions 7.a, 7.c.1, 7.c.2 and 7.d of Table 3.3.2-1~~;

b. 3.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY;

c. 3.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY;

d. 3.6.5.2.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES;

e. 3.6.5.2.2 REFUELING AREA SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES; and

f. 3.6.5.3 STANDBY GAS TREATMENT SYSTEM.

D01

APPLICABILITY: OPERATIONAL CONDITION 4, with average reactor coolant temperature greater than 200°F.

ACTION:

With the requirements of the above Specifications not satisfied:

1. Immediately enter the applicable (OPERATIONAL CONDITION 3) action for the affected Specification; or

2. Immediately suspend activities that could increase the average reactor coolant temperature or pressure and reduce the average reactor coolant temperature to 200°F or less within 24 hours.

SURVEILLANCE REQUIREMENTS

4.10.8 Verify applicable OPERATIONAL CONDITION 3 surveillances for the Specifications listed in 3.10.8 are met.

3.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS Functions 4.b, 36, 37, and 38 of Table 3.3.1-1

CORE OPERATING LIMITS REPORT

6.9.1.9 Core Operating Limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the CORE OPERATING LIMITS REPORT for the following:

a. The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) for Specification 3.2.1,

b. MAPFAC(P) and MAPFAC(F) factors for Specification 3.2.1,

c. The MINIMUM CRITICAL POWER RATIO (MCPR) and MCPR(99.9%) for Specification 3.2.3,

d. The MCPR(P) and MCPR(F) adjustment factors for specification 3.2.3,

e. The LINEAR HEAT GENERATION RATE (LHGR) for Specification 3.2.4,

f. The power biased Rod Block Monitor setpoints of Specification 3.3.6 and the Rod Block Monitor MCPR OPERABILITY limits of Specification 3.1.4.3,

g. The Reactor Coolant System Recirculation Flow upscale trip setpoint and allowable value for Specification 3.3.6,

h. The Oscillation Power Range Monitor (OPRM) period based detection algorithm (PBDA) setpoints for Specification ~~2.2.1~~, 3.3.1 D04

i. The minimum required number of operable main turbine bypass valves for Specification 3.7.8 and the TURBINE BYPASS SYSTEM RESPONSE TIME for Specification 4.7.8.c.

6.9.1.10 The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. NEDE-24011-P-A "General Electric Standard Application for Reactor Fuel" (Latest approved revision),*

b. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications, " August 1996.

6.9.1.11 The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as SHUTDOWN MARGIN, transient analysis limits, and accident analysis limits) of the safety analysis are met.

6.9.1.12 The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

REACTOR COOLANT SYSTEM (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

6.9.1.13 RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

a. Limiting Condition for Operation Section 3.4.6, "RCS Pressure/Temperature Limits"
b. Surveillance Requirement Section 4.4.6, "RCS Pressure/Temperature Limits"

The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. BWROG-TP-11-022-A, Revision 1 (SIR-05-044), "Pressure-Temperature Limits Report Methodology for Boiling Water Reactors," dated August 2013.

The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplements thereto.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report.

* For Cycle 8, specific documents were approved in the Safety Evaluation dated (5/4/98) to support License Amendment No. (127).

Unit 2

Current Technical Specifications Markup

CTS

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

d. 25 gpm total leakage averaged over any 24-hour period.

e. 1 gpm leakage at a reactor coolant system pressure of 950 ±10 psig from any reactor coolant system pressure isolation valve.**

f. 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, isolate affected component, pipe, or vessel from the reactor coolant system by use of a closed manual valve, closed and de-activated automatic valve, blind flange, or check valve within 4 hours. Otherwise, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b, c and/or d above, reduce the leakage rate to within the limits within 4 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 reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one other closed manual, deactivated automatic, or check* valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

~~d. With one or more of the high/low pressure interface valve leakage pressure monitors inoperable, restore the inoperable monitor(s) to OPERABLE status within 7 days or verify the pressure to be less than the alarm setpoint at least once per 12 hours; restore the inoperable monitor(s) 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.~~ D02

d ~~e.~~ With any reactor coolant system leakage greater than the limit in f above, identify the source of leakage within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

* Which have been verified not to exceed the allowable leakage limit at the last refueling outage or after the last time the valve was disturbed, whichever is more recent.

** Pressure isolation valve leakage is not included in any other allowable operational leakage specified in Section 3.4.3.2.

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment atmospheric gaseous radioactivity in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate in accordance with the Surveillance Frequency Control Program,

c. Monitoring the drywell unit coolers condensate flow rate in accordance with the Surveillance Frequency Control Program,

d. Monitoring the primary containment pressure in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system in accordance with the Surveillance Frequency Control Program, and

f. Monitoring the primary containment temperature in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. In accordance with the Surveillance Frequency Control Program, and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

~~4.4.3.2.3 The high/low pressure interface valve leakage pressure monitors shall be demonstrated OPERABLE with alarm setpoints set less than the specified allowable values by performance of a CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.~~ D02

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:

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 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 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.*

* 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.

SURVEILLANCE REQUIREMENTS (Continued)

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

1. Performing a system functional test which includes simulated automatic actuation and restart and verifying that each automatic valve in the flow path actuates to its correct position. ** Actual injection of coolant into the reactor vessel may be excluded.

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

~~4. Performing a CHANNEL CALIBRATION of the RCIC system discharge line "keep filled" level alarm instrumentation.~~ D03

* 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 tests. 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.

** Except for valves that are locked, sealed, or otherwise secured in the actuated position.

SPECIAL TEST EXCEPTIONS

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

LIMITING CONDITION FOR OPERATION

3.10.8 When conducting inservice leak or hydrostatic testing, the average reactor coolant temperature specified in Table 1.2 for OPERATIONAL CONDITION 4 may be increased to greater than 200°F, and operation considered not to be in OPERATIONAL CONDITION 3:

- For performance of an inservice leak or hydrostatic test,
- As a consequence of maintaining adequate pressure for an inservice leak or hydrostatic test, or
- As a consequence of maintaining adequate pressure for control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test,

provided the following OPERATIONAL CONDITION 3 Specifications are met:

a. ~~3.3.2 ISOLATION ACTUATION INSTRUMENTATION, Functions 7.a, 7.c.1, 7.c.2 and 7.d of Table 3.3.2-1~~;

D01

b. 3.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY;
c. 3.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY;
d. 3.6.5.2.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES;
e. 3.6.5.2.2 REFUELING AREA SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES; and
f. 3.6.5.3 STANDBY GAS TREATMENT SYSTEM.

APPLICABILITY: OPERATIONAL CONDITION 4, with average reactor coolant temperature greater than 200°F.

ACTION:

With the requirements of the above Specifications not satisfied:

1. Immediately enter the applicable (OPERATIONAL CONDITION 3) action for the affected Specification; or

2. Immediately suspend activities that could increase the average reactor coolant temperature or pressure and reduce the average reactor coolant temperature to 200°F or less within 24 hours.

SURVEILLANCE REQUIREMENTS

4.10.8 Verify applicable OPERATIONAL CONDITION 3 surveillances for the Specifications listed in 3.10.8 are met.

3.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS Functions 4.b, 36, 37, and 38 of Table 3.3.1-1

CORE OPERATING LIMITS REPORT

6.9.1.9 Core Operating Limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the CORE OPERATING LIMITS REPORT for the following:

a. The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) for Specification 3.2.1,

b. MAPFAC(P) and MAPFAC(F) factors for Specification 3.2.1,

c. The MINIMUM CRITICAL POWER RATIO (MCPR) and MCPR(99.9%) for Specification 3.2.3,

d. The MCPR(P) and MCPR(F) adjustment factor for specification 3.2.3,

e. The LINEAR HEAT GENERATION RATE (LHGR) for Specification 3.2.4,

f. The power biased Rod Block Monitor setpoints of Specification 3.3.6 and the Rod Block Monitor MCPR OPERABILITY limits of Specification 3.1.4.3.

g. The Reactor Coolant System Recirculation Flow upscale trip setpoint and allowable value for Specification 3.3.6,

h. The Oscillation Power Range Monitor (OPRM) period based detection algorithm (PBDA) setpoints for Specification 2.2.1, 3.3.1 D04

i. The minimum required number of operable main turbine bypass valves for Specification 3.7.8 and the TURBINE BYPASS SYSTEM RESPONSE TIME for Specification 4.7.8.c.

6.9.1.10 The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. NEDE-24011-P-A "General Electric Standard Application for Reactor Fuel" (Latest approved revision),

b. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications, " August 1996.

6.9.1.11 The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as SHUTDOWN MARGIN, transient analysis limits, and accident analysis limits) of the safety analysis are met.

6.9.1.12 The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

REACTOR COOLANT SYSTEM (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

6.9.1.13 RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

a. Limiting Condition for Operation Section 3.4.6, "RCS Pressure/Temperature Limits"
b. Surveillance Requirement Section 4.4.6, "RCS Pressure/Temperature Limits"

The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. BWROG-TP-11-022-A, Revision 1 (SIR-05-044), “Pressure-Temperature Limits Report Methodology for Boiling Water Reactors," dated August 2013.

The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplements thereto.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report.

Discussion of Changes

Discussion of Changes

Other Affected Technical Specifications

3/4.4.3.2, Operational Leakage
3/4.7.3, Reactor Core Isolation Cooling System
3/4.10.8, Inservice Leak and Hydrostatic Testing
6.9.1.9, Core Operating Limits Report

D01

Current TS 3.10.8, "Inservice Leak and Hydrostatic Testing," LCO states that certain specifications must be met. Paragraph a of the LCO specifies, "3.3.2 ISOLATION ACTUATION INSTRUMENTATION, Functions 7.a, 7.c.1, 7.c.2 and 7.d of Table 3.3.2-1." The requirement is revised to reflect the proposed specifications to state, "3.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS Functions 4.b, 36, 37, and 38 of Table 3.3.1-1."

The affected Functions are:

Current TS Table 3.3.2-1 Function	Title	Proposed TS Table 3.3.1-1 Function	Title
7.a	Water Level Low, Low - Level 2	4.b	Reactor Vessel Water Level - Wide Range, Low, Low - Level 2
7.c.1	Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	37	Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High
7.c.2	Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	38	Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High
7.d	Reactor Enclosure Ventilation Exhaust Duct Radiation - High	36	Reactor Enclosure Ventilation Exhaust Duct- Radiation - High

This change is acceptable because it revises the existing requirement to reference the relocated and renumbered requirements without making a technical change.

D02

Current TS 3.4.3.2, "Operational Leakage," contains a Surveillance Requirement and Action on the high/low pressure interface valve leakage pressure monitors. These monitors are alarm-only functions that alert the operator to reactor coolant system pressure isolation valve leakage. The SR 4.4.3.2.3 and the associated Action d are removed in the proposed TS. Subsequent Action e is renumbered to Action d.

CEG evaluated alarm-only indications for inclusion in the new control room design and, although the alarm was chosen to be maintained due to the defense-in-depth, it is not critical to either identification or response in an accident or transient condition or required to satisfy the LCO. As such, the alarm is being relocated from the TS. Relocation of these requirements from the TS to licensee procedures is consistent with the standard TS (NUREG-1433). As stated in NEDC-31681, "Improved BWR Technical Specifications," Volume 4, April 1989:

> "Requirements for high/low pressure interface valve leakage monitors have been relocated to plant specific procedures since they are alarm only instrumentation. They represent part of routine operational monitoring and plant specific controls are applicable. These instruments do not represent instruments which support the LCO."

The NRC accepted this justification and the high/low pressure interface valve leakage monitors were not included in NUREG-1433. This change is acceptable because the high/low pressure interface valve leakage monitors are not instruments required to satisfy the LCO and can be placed under licensee control.

D03

Current TS 3.7.3, "Reactor Core Isolation Cooling System," SR 4.7.3.c.4 requires the performance of a Channel Calibration of the RCIC System discharge line "keep filled" level alarm instrumentation. In the proposed TS, this alarm function is removed from the TS and placed under licensee control.

Current SR 4.7.3, which is unaffected by the proposed change, requires verification that locations susceptible to gas accumulation are sufficiently filled with water. The "keep filled" system and associated alarm are a method to ensure the system is sufficiently filled with water. However, the alarm is not required and the surveillance can be satisfied without it. There are no equivalent requirements in the standard TS (NUREG-1433). This change is acceptable because the "keep filled" system and alarm are not required to satisfy the LCO and can be placed under licensee control.

D04

Current TS 6.9.1.9, "Core Operating Limits Report," contains a reference to the Oscillation Power Range Monitor setpoints in TS 2.2.1. The reference is revised to reflect the proposed specifications, which moved this requirement from current TS 2.2.1 to proposed TS 3.3.1. This change is acceptable because it revises the existing requirement to reference the relocated requirements without making a technical change.

Unit 1

Proposed Technical Specifications

CTS

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

d. 25 gpm total leakage averaged over any 24-hour period.

e. 1 gpm leakage at a reactor coolant system pressure of 950 ±10 psig from any reactor coolant system pressure isolation valve.**

f. 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, isolate affected component, pipe, or vessel from the reactor coolant system by use of a closed manual valve, closed and de-activated automatic valve, blind flange, or check valve within 4 hours. Otherwise, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b, c and/or d above, reduce the leakage rate to within the limits within 4 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 reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one other closed manual, deactivated automatic, or check* valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With any reactor coolant system leakage greater than the limit in f above, identify the source of leakage within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

---

* Which have been verified not to exceed the allowable leakage limit at the last refueling outage or after the last time the valve was disturbed, whichever is more recent.

** Pressure isolation valve leakage is not included in any other allowable operational leakage specified in Section 3.4.3.2.

REACTOR COOLANT SYSTEM

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment atmospheric gaseous radioactivity in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate in accordance with the Surveillance Frequency Control Program,

c. Monitoring the drywell unit coolers condensate flow rate in accordance with the Surveillance Frequency Control Program,

d. Monitoring the primary containment pressure in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system in accordance with the Surveillance Frequency Control Program, and

f. Monitoring the primary containment temperature in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. In accordance with the Surveillance Frequency Control Program, and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 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:

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 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 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.*

---

* 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.

SURVEILLANCE REQUIREMENTS (Continued)

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

1. Performing a system functional test which includes simulated automatic actuation and restart and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded.

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

*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 tests. 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.

CTS

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

LIMITING CONDITIONS FOR OPERATION

3.10.8 3.10.8 When conducting inservice leak or hydrostatic testing, the average reactor coolant temperature specified in Table 1.2 for OPERATIONAL CONDITION 4 may be increased to greater than 200°F, and operation considered not to be in OPERATIONAL CONDITION 3:

- For performance of an inservice leak or hydrostatic test,
- As a consequence of maintaining adequate pressure for an inservice leak or hydrostatic test, or
- As a consequence of maintaining adequate pressure for control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test,

provided the following OPERATIONAL CONDITION 3 Specifications are met:

a. 3.3.1	PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS Functions 4.b, 36, 37, and 38 of Table 3.3.1-1.
b. 3.6.5.1.1	REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY;
c. 3.6.5.1.2	REFUELING AREA SECONDARY CONTAINMENT INTEGRITY;
d. 3.6.5.2.1	REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES;
e. 3.6.5.2.2	REFUELING AREA SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES; and
f. 3.6.5.3	STANDBY GAS TREATMENT SYSTEM.

APPLICABILITY: OPERATIONAL CONDITION 4, with average reactor coolant temperature greater than 200°F.

ACTION:

With the requirements of the above Specifications not satisfied:

1. Immediately enter the applicable (OPERATIONAL CONDITION 3) action for the affected Specification; or

2. Immediately suspend activities that could increase the average reactor coolant temperature or pressure and reduce the average reactor coolant temperature to 200°F or less within 24 hours.

SURVEILLANCE REQUIREMENTS

4.10.8 Verify applicable OPERATIONAL CONDITION 3 surveillances for the Specifications listed in 3.10.8 are met.

ADMINISTRATIVE CONTROLS

CORE OPERATING LIMITS REPORT

6.9.1.9 6.9.1.9 Core Operating Limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the CORE OPERATING LIMITS REPORT for the following:

a. The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) for Specification 3.2.1,

b. MAPFAC(P) and MAPFAC(F) factors for Specification 3.2.1,

c. The MINIMUM CRITICAL POWER RATIO (MCPR) and MCPR(99.9%) for Specification 3.2.3,

d. The MCPR(P) and MCPR(F) adjustment factors for specification 3.2.3,

e. The LINEAR HEAT GENERATION RATE (LHGR) for Specification 3.2.4,

f. The power biased Rod Block Monitor setpoints of Specification 3.3.6 and the Rod Block Monitor MCPR OPERABILITY limits of Specification 3.1.4.3,

g. The Reactor Coolant System Recirculation Flow upscale trip setpoint and allowable value for Specification 3.3.6,

h. The Oscillation Power Range Monitor (OPRM) period based detection algorithm (PBDA) setpoints for Specification 3.3.1,

i. The minimum required number of operable main turbine bypass valves for Specification 3.7.8 and the TURBINE BYPASS SYSTEM RESPONSE TIME for Specification 4.7.8.c.

6.9.1.10 The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. NEDE-24011-P-A "General Electric Standard Application for Reactor Fuel" (Latest approved revision),*

b. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications, " August 1996.

6.9.1.11 The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as SHUTDOWN MARGIN, transient analysis limits, and accident analysis limits) of the safety analysis are met.

6.9.1.12 The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

REACTOR COOLANT SYSTEM (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

6.9.1.13 RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

a. Limiting Condition for Operation Section 3.4.6, "RCS Pressure/Temperature Limits"
b. Surveillance Requirement Section 4.4.6, "RCS Pressure/Temperature Limits"

The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. BWROG-TP-11-022-A, Revision 1 (SIR-05-044), "Pressure-Temperature Limits Report Methodology for Boiling Water Reactors," dated August 2013.

The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplements thereto.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report.

* For Cycle 8, specific documents were approved in the Safety Evaluation dated (5/4/98) to support License Amendment No. (127).

Unit 2

Proposed Technical Specifications

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

d. 25 gpm total leakage averaged over any 24-hour period.

e. 1 gpm leakage at a reactor coolant system pressure of 950 ±10 psig from any reactor coolant system pressure isolation valve.**

f. 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, isolate affected component, pipe, or vessel from the reactor coolant system by use of a closed manual valve, closed and de-activated automatic valve, blind flange, or check valve within 4 hours. Otherwise, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b, c and/or d above, reduce the leakage rate to within the limits within 4 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 reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one other closed manual, deactivated automatic, or check* valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With any reactor coolant system leakage greater than the limit in f above, identify the source of leakage within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

* Which have been verified not to exceed the allowable leakage limit at the last refueling outage or after the last time the valve was disturbed, whichever is more recent.

** Pressure isolation valve leakage is not included in any other allowable operational leakage specified in Section 3.4.3.2.

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment atmospheric gaseous radioactivity in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate in accordance with the Surveillance Frequency Control Program,

c. Monitoring the drywell unit coolers condensate flow rate in accordance with the Surveillance Frequency Control Program,

d. Monitoring the primary containment pressure in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system in accordance with the Surveillance Frequency Control Program, and

f. Monitoring the primary containment temperature in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. In accordance with the Surveillance Frequency Control Program, and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

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:

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 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 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.*

---

* 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.

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

1. Performing a system functional test which includes simulated automatic actuation and restart and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded.

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

*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 tests. 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.

CTS SPECIAL TEST EXCEPTIONS

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

LIMITING CONDITIONS FOR OPERATION

3.10.8 3.10.8 When conducting inservice leak or hydrostatic testing, the average reactor coolant temperature specified in Table 1.2 for OPERATIONAL CONDITION 4 may be increased to greater than 200°F, and operation considered not to be in OPERATIONAL CONDITION 3:

- For performance of an inservice leak or hydrostatic test,
- As a consequence of maintaining adequate pressure for an inservice leak or hydrostatic test, or
- As a consequence of maintaining adequate pressure for control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test,

provided the following OPERATIONAL CONDITION 3 Specifications are met:

a. 3.3.1	PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS Functions 4.b, 36, 37, and 38 of Table 3.3.1-1.
b. 3.6.5.1.1	REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY;
c. 3.6.5.1.2	REFUELING AREA SECONDARY CONTAINMENT INTEGRITY;
d. 3.6.5.2.1	REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES;
e. 3.6.5.2.2	REFUELING AREA SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES; and
f. 3.6.5.3	STANDBY GAS TREATMENT SYSTEM.

APPLICABILITY: OPERATIONAL CONDITION 4, with average reactor coolant temperature greater than 200°F.

ACTION:

With the requirements of the above Specifications not satisfied:

1. Immediately enter the applicable (OPERATIONAL CONDITION 3) action for the affected Specification; or

2. Immediately suspend activities that could increase the average reactor coolant temperature or pressure and reduce the average reactor coolant temperature to 200°F or less within 24 hours.

SURVEILLANCE REQUIREMENTS

4.10.8 Verify applicable OPERATIONAL CONDITION 3 surveillances for the Specifications listed in 3.10.8 are met.

CTS

CORE OPERATING LIMITS REPORT

6.9.1.9 6.9.1.9 Core Operating Limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the CORE OPERATING LIMITS REPORT for the following:

a. The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) for Specification 3.2.1,

b. MAPFAC(P) and MAPFAC(F) factors for Specification 3.2.1,

c. The MINIMUM CRITICAL POWER RATIO (MCPR) and MCPR(99.9%) for Specification 3.2.3,

d. The MCPR(P) and MCPR(F) adjustment factors for specification 3.2.3,

e. The LINEAR HEAT GENERATION RATE (LHGR) for Specification 3.2.4,

f. The power biased Rod Block Monitor setpoints of Specification 3.3.6 and the Rod Block Monitor MCPR OPERABILITY limits of Specification 3.1.4.3,

g. The Reactor Coolant System Recirculation Flow upscale trip setpoint and allowable value for Specification 3.3.6,

h. The Oscillation Power Range Monitor (OPRM) period based detection algorithm (PBDA) setpoints for Specification 3.3.1,

i. The minimum required number of operable main turbine bypass valves for Specification 3.7.8 and the TURBINE BYPASS SYSTEM RESPONSE TIME for Specification 4.7.8.c.

6.9.1.10 The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. NEDE-24011-P-A "General Electric Standard Application for Reactor Fuel" (Latest approved revision),*

b. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications, " August 1996.

6.9.1.11 The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as SHUTDOWN MARGIN, transient analysis limits, and accident analysis limits) of the safety analysis are met.

6.9.1.12 The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

REACTOR COOLANT SYSTEM (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

6.9.1.13 RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

a. Limiting Condition for Operation Section 3.4.6, "RCS Pressure/Temperature Limits"
b. Surveillance Requirement Section 4.4.6, "RCS Pressure/Temperature Limits"

The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. BWROG-TP-11-022-A, Revision 1 (SIR-05-044), "Pressure-Temperature Limits Report Methodology for Boiling Water Reactors," dated August 2013.

The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplements thereto.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report.

Unit 1

Revised Technical Specifications Bases (For Information Only)

None. The Bases are not affected.

Unit 2

Revised Technical Specifications Bases (For Information Only)

None. The Bases are not affected.

Attachment 3

License Amendment Request

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

WNA-DS-04899-GLIM-P, Revision 1

Limerick Generating Station Plant Protection System Digital Modernization Project
System Requirement Specification

PROPRIETARY

Attachment 4

License Amendment Request

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

WNA-AR-01050-GLIM-P

Limerick Generating Station Plant Protection System
Failure Modes and Effects Analysis," Revision 2

PROPRIETARY

Attachment 5

License Amendment Request

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

WNA-DS-04900-GLIM-P

Limerick Generating Station Plant Protection System Digital Modernization Project
System Design Specification (SyDS), Revision 2

PROPRIETARY

Attachment 6

License Amendment Request

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

EQ-EV-386-GLIM-P

Comparison of Equipment Qualification Hardware Testing for Common Q Applications to Limerick Requirements," Revision 2

PROPRIETARY

Attachment 7

License Amendment Request

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

CAW-22-049

Affidavit, Proprietary Information Notice, and Copyright in support of WNA-DS-04899-GLIM-P, Revision 1, WNA-AR-01050-GLIM-P, Revision 2, WNA-DS-04900-GLIM-P, Revision 2, and EQ-EV-386-GLIM-P, Revision 2 (Attachments 3, 4, 5, and 6)

Commonwealth of Pennsylvania:
County of Butler:

(1) I, Zachary Harper, Manager, Licensing Engineering, have been specifically delegated and authorized to apply for withholding and execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse).

(2) I am requesting the proprietary portions of WNA-DS-04899-GLIM, Revision 1, WNA-AR-01050-GLIM, Revision 2, WNA-DS-04900-GLIM, Revision 2, and EQ-EV-386-GLIM, Revision 2 be withheld from public disclosure under 10 CFR 2.390.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged, or as confidential commercial or financial information.

(4) Pursuant to 10 CFR 2.390, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

- (i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse and is not customarily disclosed to the public.
- (ii) The information sought to be withheld is being transmitted to the Commission in confidence and, to Westinghouse's knowledge, is not available in public sources.
- (iii) Westinghouse notes that a showing of substantial harm is no longer an applicable criterion for analyzing whether a document should be withheld from public disclosure. Nevertheless, public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar technical evaluation justifications and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

(5) Westinghouse has policies in place to identify proprietary information. Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

- (a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.
- (b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage (e.g., by optimization or improved marketability).
- (c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.
- (d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.
- (e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.
- (f) It contains patentable ideas, for which patent protection may be desirable.

(6) The attached submittal contains proprietary information throughout, for the reasons set forth in Sections (5) (a) and (c) of this Affidavit. Accordingly, a redacted version would be of no value to the public.

I declare that the averments of fact set forth in this Affidavit are true and correct to the best of my knowledge, information, and belief. I declare under penalty of perjury that the foregoing is true and correct.

Executed on: 9/20/2022

Signed electronically by
Zachary Harper

Approval Information
Manager Approval Harper Zachary S Sep-20-2022 13:24:41

Files approved on Sep-20-2022

Attachment 8.1

License Amendment Request

Limerick Generating Station, Units 1 and 2

Docket Nos. 50-352 and 50-353

Human Factors Engineering

LGS Digital Modernization Project - Application of Human Factors Engineering Principles

INL/RPT-22-68693, "Human Factors Engineering Program Plan for Constellation Safety Related Instrumentation and Control Upgrades," July 2022

INL/RPT-22-68995, Rev 1, "Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report," May 3, 2023 (non-CEG proprietary)

CEG Proprietary affidavit for INL/RPT-22-68995

LGS Digital Modernization Project
Application of Human Factors Engineering Principles

1. SUMMARY

The Limerick Generating Station Units 1 and 2 (LGS) Human Factors Engineering (HFE) Program Plan for the LGS Digital Modernization Project (INL/RPT-22-68693, "Human Factors Engineering Program Plan for Constellation Safety-Related Instrumentation and Control Upgrades," Revision 0, July 2022) (Reference 1) is the HFE process that Constellation Energy Generation, LLC (CEG) utilized to design the modified LGS control room, as well as verify that HFE principles were appropriately applied. The LGS HFE Program Plan for the structures, systems, and components (SSCs) affected by the LGS Modernization Project, as well as the associated procedures, is based on the twelve HFE elements within NUREG-0711, "Human-System Interface Design Review Guidelines," Revision 3. In addition, the HFE Program Plan satisfies the current LGS HFE licensing basis requirements specified in NUREG-0737 Supplement 1, Item I.D.1, and applies generally accepted HFE principles.

Even though the LGS HFE Program Plan provides guidance for the design organization on all twelve NUREG-0711 elements, not all twelve HFE elements strictly relate to the requirements in NUREG-0737 Supplement 1, Item I.D.1. The additional HFE activities performed per NURG-0711, Revision 3 for the SSCs and procedures affected by the LGS Modernization Project, beyond those required by NUREG-0737 Supplement 1, Item I.D.1, expand the LGS HFE licensing basis only for those specific SSCs and procedures.

The results of the relevant HFE analyses and validation and verification (V&V) activities for these HFE elements are provided in the HFE Program Plan, as discussed below.

2. INTRODUCTION

After the Three Mile Island Unit 2 (TMI-2) accident, the NRC issued new action plans, requirements, and guidance to applicants and licensees to address certain items they deemed necessary to correct or improve the operation of nuclear facilities. The approved TMI-2 action plan requirements are provided in NUREG-0737, "Clarification of TMI Action Plan Requirements," and NUREG-0737 Supplement 1, "Supplement 1 to NUREG-0737 - Emergency Response Capability (Generic Letter No. 82-33)," which replaced the requirements in NUREG-0737.

In NUREG-0737 Supplement 1, the NRC required applicants and licensees to review their control room design, consider human factors engineering (HFE) principles, and make any necessary changes to improve the ability of control room operators to respond to emergency conditions. These post-TMI requirements continue to be the underlying HFE-related regulatory and licensing basis requirements for LGS. The following sections summarize these requirements, how they were previously satisfied, and how they are applied and satisfied for the current LGS main control room modification activities.

3. HFE-RELATED REGULATORY AND LICENSING BASIS REQUIREMENTS, AND KEY GUIDANCE

This section describes the underlying HFE-related regulatory and licensing basis requirements applicable to the LGS control room design. It also describes the use of one key regulatory guidance document.

a. 10 CFR 50, Appendix A, General Design Criteria 19

The General Design Criteria (GDC) in Appendix A to 10 CFR Part 50 establish minimum design requirements for water-cooled nuclear power plants. GDC 19 includes the design requirements for control rooms. Specifically, it requires, in part, a control room to be provide from which actions can be taken for normal and accident conditions.

b. LGS UFSAR

LGS UFSAR Section 1.13.2 summarizes the TMI-2 NUREG-0737 requirements and the LGS responses to the requirements. NUREG-0737 Item I.D.1, "Control Room Design Reviews," captures the requirement to review the control room design, consider human factors engineering principles, and make any necessary changes to improve the ability of control room operators to respond to emergency conditions.

c. NUREG-0737, NUREG-0737 Supplement 1 (Generic Letter No. (GL) 82-33)

NUREG-0737 includes requirements associated with planning and performing a Detailed Control Room Design Review (DCRDR), which is the central HFE-related requirement following the TMI-2 accident. NUREG-0737 Supplement 1 replaced the DCRDR requirements from NUREG-0737.

In accordance with UFSAR Section 1.13.2 and NUREG-0737 Supplement 1 Item I.D.1, a DCRDR must be performed to verify that the control room design applies human factors principles. Specifically, this item required licensees and applicants for operating licenses to submit a DCRDR program plan and conduct a DCRDR to identify and correct control room design deficiencies that would contribute to a significant reduction of risk and an enhancement in the safety of operation. The goal of these requirements was to develop a process to confirm that the control room is adequately designed to deal with emergency conditions.

The following is a summary of the LGS DCRDR methodology, consistent with NUREG-0737 Supplement 1, Item I.D.1:

- A qualified review team and review program incorporating human engineering principles are used.
- A function and task analysis (that had been used as the basis for developing emergency operating procedures Technical Guidelines and plant specific emergency operating procedures) are performed to identify control room operator

tasks and information and control requirements during emergency operations.

- A comparison of the display and control requirements with a control room inventory is performed to identify missing displays and controls.
- A control room survey is performed to identify deviations from accepted human factors principles. This survey includes, among other things, an assessment of the control room layout, the usefulness of audible and visual alarm systems, the information recording and recall capability, and the control room environment.
- Human Engineering Discrepancies (HEDs) are identified and assessed to determine which are significant enough to require correction.
- Design improvements are developed to correct those discrepancies.
- The selected design improvements are verified to provide the necessary correction.

d. NUREG-0700, Revision 0

NUREG-0737 notes that the NRC issued NUREG-0700, "Guidelines for Control Room Design Reviews," Revision 0 to provide guidance to licensees and applicants for performing DCRDRs. Therefore, the LGS DCRDR program plan (Reference 2) and report (References 3, 4, and 5) used NUREG-0700, Revision 0 as input for developing their process and performing their DCRDR.

4. PREVIOUS COMPLIANCE WITH HFE-RELATED REQUIREMENTS FOR THE ORIGINAL CONTROL ROOM

To address NUREG-0737 Supplement 1, Item I.D.1 when it was originally issued in the 1980s, the BWR Owner's Group developed a DCRDR control room survey (Reference 6). The BWR Owner's Group control room survey addressed the planning and review phases of the DCRDR program. The licensee for LGS subsequently developed a DCRDR program plan to address the assessment, implementation, and verification phases (Reference 2). Both documents, along with the DCRDR results (References 3, 4, and 5), were submitted to the NRC for review and approval.

The NRC staff reviewed and accepted the BWR Owner's Group control room survey in Reference 7 and the LGS DCRDR program plan in Reference 8. In their review of the LGS DCRDR program plan, the NRC concluded that if the activities described in the plan are properly executed, they should define and correct the major HEDs which exist in the control room. As such, the NRC staff determined that the LGS DCRDR results satisfied the requirements in NUREG-0737 Supplement 1 and NUREG-0700, Revision 0 (References 9, 10, 11, and 12).

5. COMPLIANCE WITH THE HFE-RELATED REQUIREMENTS FOR THE LGS MODERNIZATION PROJECT CONTROL ROOM

a. General Strategy for Addressing HFE Requirements

The HFE processes applied to the LGS modified control room design program satisfy the NUREG-0737 Supplement 1, Item I.D.1 HFE requirements. This ensures human factors principles are applied and confirm the control room continues to be capable of adequately responding to emergency conditions.

As documented in the DCRDR program plan, CRDR results, and the NRC Safety Evaluation Reports, the previous CRDR review was performed and reviewed against NUREG-0737 Supplement 1 and NUREG-0700, Revision 0. The NRC found the LGS DCRDR satisfied both documents. In a similar way, the current control room modification is performed under an LGS HFE Program Plan, results are issued for the activities performed in accordance with the LGS HFE Program Plan (see Table 2), and the activities are shown to meet the requirements in NUREG-0737 Supplement 1 Item I.D.1 (see Table 1).

NUREG-0700, Revision 0 provides detailed guidance for performing a DCRDR. However, it is partially based on outdated technology and is not relevant to the LGS control room modification project, nor does it represent a binding requirement for licensees and applicants. Subsequent revisions to NUREG-0700 broaden its scope and address modern technology. Therefore, the LGS HFE program plan references the latest version of NUREG-0700 as the basis for the LGS control room style guide.

In addition to the requirements above, DI&C-ISG-06 Section B.1.4 states that the NRC will perform their HFE safety evaluation in accordance with SRP Chapter 18, "Human Factors Engineering," NUREG-0711, and NUREG-1764, "Guidance for the Review of Changes to Human Actions." DI&C-ISG-06 also describes how the NRC staff reviews an LAR to determine whether the LAR addresses IEEE Std 603-1991, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations,", including the HFE information in Clause 5.8. This NRC guidance was taken into consideration in the development of the LGS HFE strategy, as discussed below.

b. Technical Justification

The LGS HFE Program Plan and the implementation of the activities described in the program plan address the underlying regulatory and licensing basis requirements for the plant, and any additional relevant NRC guidance. WCAP-18598-P, "Licensing Technical Report for the Limerick Generating Station Units 1&2 Digital Modernization Project" [Attachment 3 to the License Amendment Request (LAR)] also addresses certain HFE items. This regulatory basis is discussed below.

i. NUREG-0737 Supplement 1, Item I.D.1

The LGS HFE Program Plan describes the process to be used for applying HFE principles within the modernized control room. Consistent with the CRDR program plan referenced in UFSAR Section 1.13.2 used to satisfy NUREG-0737 Supplement 1 Item I.D.1, the LGS HFE program plan includes processes for function analysis (also referred to as functional requirements analysis and function allocation), task analysis, identification and processing of HEDs, and verification that the design satisfies the underlying requirements and needs of the operators.

Table 1 provides a comparison of the LGS HFE Program Plan to NUREG-0737 Supplement 1, Item I.D.1, and the NRC-approved LGS DCRDR methodology to demonstrate continued compliance with the underlying programmatic requirements. This table illustrates how the current LGS HFE Program Plan addresses the same activities required and covered by NUREG-0737 Supplement 1, Item I.D.1 and the LGS DCRDR program plan.

ii. GDC 19

The activities in the LGS HFE program plan are the means for ensuring that, in accordance with GDC 19, a control room is provided "from which actions can be taken to operate the nuclear power unit safety" under various plant conditions.

iii. NUREG-0800, Standard Review Plan, Chapter 18, "Human Factors Engineering"

As stated in NUREG-0800 Section I.1, item 4, the NRC reviews HFE plant modifications as part of the change process described in 10 CFR 50.59. Item 5 notes that the NRC reviews changes to important human actions. Similar to DI&C-ISG-06, NUREG-0800 refers to NUREG-0711 and NUREG-1764 as the process used to review a licensee’s HFE activities and confirm that important human actions are adequately addressed. The following discussion describes the integration of NUREG-0711 and NUREG-1764 into the LGS HFE strategy.

iv. NUREG-0711, Revision 3

The LGS HFE Program Plan format and content are based on the twelve HFE elements within NUREG-0711, Revision 3. The results of the HFE analysis and

V&V activities performed in accordance with the LGS HFE Program Plan [i.e., the Results Summary Reports (RSRs) (References 13 and 14)] are included in this attachment, following the HFE Program Plan. Table 2 provides the key conclusions from the RSRs, cross referenced to the associated NUREG-0711, Revision 3 element and the corresponding HFE Program Plan section.

Even though the LGS HFE Program Plan provides guidance for the design organization on all twelve NUREG-0711 elements, not all twelve HFE elements strictly relate to the requirements in NUREG-0737 Supplement 1, Item I.D.1. The additional HFE activities performed per NURG-0711, Revision 3 for the SSCs and procedures affected by the LGS Modernization Project, beyond those required by NUREG-0737 Supplement 1, Item I.D.1, expand the LGS HFE licensing basis only for those specific SSCs and procedures.

v. NUREG-1764, "Guidance for the Review of Changes to Human Actions"

According to the LGS HFE Program Plan, any new important human actions (HAs) are identified by a screening analysis as described in NUREG-1764. A risk-informed approach, per NUREG-1764, is then used to determine the appropriate level of HFE review. This is discussed in Section 6.8 of the LGS HFE Program Plan.

vi. IEEE 603-1991

IEEE 603-1991, Clause 5.8 provides HFE information related to information displays in the control room. This includes information related to displays for manually controlled actions, system status indication, indication of bypasses, and the location of information displays. WCAP-18598-P (Reference 15), Sections 3.2.24.1.3 through 3.2.24.1.6, address these requirements. The safety displays are accessible to the operators in the control room and include the necessary information to safely operate the plant, as described in IEEE 603-1991. The ability of the operator to effectively use the updated displays and controls is evaluated according to the LGS HFE Program Plan and documented in the RSRs.

6. REFERENCES

1. INL/RPT-22-68693, "Human Factors Engineering Program Plan for Constellation Safety-Related Instrumentation and Control Upgrades," July 2022
2. "Detailed Control Room Design Review Program Plan for Philadelphia Electric Company's Limerick and Peach Bottom Plants," (*LGS DCRDR Program Plan*) (ADAMS Accession No. ML20077M381), dated August 31, 1983,
3. "Philadelphia Electric Company Limerick Plant Control Room Design Review Final Report," (*LGS DCRDR Summary Report*) (ADAMS Accession No. ML20092K946), dated June 1984,
4. "Philadelphia Electric Company's Limerick Plant Control Room Design Review Supplemental Report Number 1 Final Report of June 1984," (*LGS DCRDR Summary Report Supplement 1*), (ADAMS Accession No. ML20107G642), dated October 1984,
5. "Philadelphia Electric Company's Limerick Generating Station Control Room Design Review Supplemental Report 2 to the Final Report of June 1985," *(LGS DCRDR Summary Report Supplement 2*) (ADAMS Accession No. ML20129C386), dated June 1985
6. "BWR Owner's Group Control Room Improvements Committee Human Factors Design Review of the Limerick 1 & 2 Control Room Summary Report," (ADAMS Accession No.ML20092K972), dated April 1982,
7. Generic Letter 83-18, "NRC Staff Review of the BWR Owners' Group (BWROG) Control Room Survey Program"
8. U.S. Nuclear Regulatory Commission (NRC) letter to Philadelphia Electric Company (PECo), "Detailed Control Room Design Review for Limerick Unit 1," (ADAMS Accession No.ML20082Q834), dated November 25, 1983
9. NRC letter to PECo, "Detailed Control Room Design for Limerick" (*NRC in-process audit of the Limerick DCRDR*), (ADAMS Accession No. ML20092K044), dated June 21, 1984
10. "Technical Evaluation Report of the Detailed Control Room Design Review for Philadelphia Electric Company's Limerick Generating Station," (ADAMS Accession No. ML20106A525), dated August 10, 1984
11. NUREG-0991 Supplement No. 3, "Safety Evaluation Report related to the operation of Limerick Generating Station, Units 1 and 2," October 1984

12. NUREG-0991 Supplement No. 5, "Safety Evaluation Report related to the operation of Limerick Generating Station, Units 1 and 2," July 1985

13. INL/RPT-22-68703, "Human Factors Engineering Operating Experience Review of the Constellation Limerick Control Room Upgrade: Results Summary Report," July 2022

14. INL/RPT-22-68995, "Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report," July 2022

15. CEG letter to the NRC, "Review of Limerick Generating Station Defense in Depth and Diversity Common Cause Failure Coping Analysis, WNA-AR-01074-GLIM-P, Revision 2, July 2022, and the Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project, WCAP-18598-P, Revision 0, July 2022," dated August 12, 2022 (ADAMS Accession No. ML22224A146)

Table 1
Comparison of the LGS HFE Program Plan to NUREG-0737 Supplement 1

NUREG-0737 Supplement 1 (Item I.D.1) Section #	DCRDR and NUREG-0737 Supplement 1 Requirement Summary	Application to Current Modification Project	Relevant HFE Program Plan Sections
5.1.b(i)	Establishment of a qualified multidisciplinary review team	Section 6.1 of the LGS HFE program plan establishes an HFE team to evaluate the HFE aspects of the new control room design. It is a multidisciplinary team that includes I&C and digital engineers, operators, HSI engineers, system engineers, PRA and HRA experts.	Section 6.1
5.1.b(i)	Establishment of a review program incorporating accepted human engineering principles	The LGS HFE program plan is established to govern the HFE review activities to be performed as part of the control room modification. It incorporates accepted human engineering principles from documents such as NUREG-0711 Revision 3, NUREG-0700 Revision 3, NUREG-1764 Revision 1, EPRI guidance documents, and IEEE standards. The full list of HFE documents used as input is included in the LGS HFE program plan reference section (Section 8).	Entire document Section 8

LGS Digital Modernization Project
Application of Human Factors Engineering Principles

5.1.b(ii)	Use of function and task analysis (that had been used as the basis for developing emergency operating procedures Technical Guidelines and plant specific emergency operating procedures) to identify control room operator tasks and information and control requirements during emergency operations. This analysis has multiple purposes and should also serve as the basis for developing training and staffing needs and verifying SPDS parameters.	Function analysis (also called function requirements analysis and function allocation) is the identification of functions that must be performed to satisfy the nuclear power plant's overall goals and the assignment of the functions to personnel, automatic systems, or a combination of both. As part of the modification, existing functions are reassigned (e.g., from manual control to automatic control). Therefore, a function analysis is performed in accordance with Section 6.5 of the LGS HFE program plan to review the new reassignments. Task analysis is the analysis of functions that have been assigned to plant personnel. Since plant personnel tasks will change as part of the control room modification, a task analysis is performed in accordance with Section 6.6 of the LGS HFE program plan. Per the Section 6.14 of the LGS HFE program plan, training associated with the modification are based upon analysis of job and task requirements impacted by the modification as identified in the task analysis. Training program changes will address all personnel tasks affected by the changes in plant systems and HSIs. In addition, LGS HFE program plan Section 6.7 notes that staffing and qualifications need to be consistent with the demands of the tasks that are assigned. Task analysis for the upgrade provides important input, defining the knowledge, skills and abilities required to perform tasks assigned to staff members. The Safety Parameter Display System (SPDS) is included in the task analysis and verified as part of the LGS V&V activities, as required.	Section 6.5 Section 6.6 Section 6.7 Section 6.14
5.1.b(iii)	Comparison of display and control requirements with control room inventory, identify any missing displays or controls	The task analysis, as described above for NUREG-0737 Supplement 1 Section 5.1.b(ii), will compare display and control requirements of the modified design with control room inventory. This activity verifies all required functions necessary for emergency operations have the necessary displays and controls.	Section 6.6
5.1.b(iv)	Performance of a control room survey to identify any deviations from accepted HFE principles (layout, environment, etc.)	The control room survey is addressed by the function and task analysis and V&V activities described elsewhere (see description of NUREG-0737 Supplement 1 Section 5.1.b(ii) and 5.1.d).	Section 6.5 Section 6.6 Section 6.15 Section 6.16
5.1.c	Identification of significant HEDs to be corrected	A V&V process is performed on the modified control room design (see NUREG-0737 Supplement 1 Section 5.1.d below). HEDs are identified during this V&V process. At a minimum, HEDs are identified for features that do not meet the underlying regulatory and licensing basis requirements. See Section 6.15 and Section 6.16 of the LGS HFE program plan for a description of the V&V process and how HEDs are identified.	Section 6.15 Section 6.16

LGS Digital Modernization Project
Application of Human Factors Engineering Principles

5.1.c	Selection of design improvements to correct significant HEDs	Significant HEDs identified during the V&V of the modified control room design are addressed through procedure changes, operating training, or design improvements. See Section 6.15 and Section 6.16 of the LGS HFE program plan for a description how HEDs are resolved.	Section 6.15 Section 6.16
5.1.d	Verification that the design improvements provide the necessary correction	A V&V process is performed on the modified control room design to verify and validate that the design meets the underlying HFE requirements. Any HEDs identified during the V&V process are addressed through procedure changes, operating training, or design improvements. These subsequent changes to procedures, training, or design are evaluated to confirm that they satisfy the underlying HFE requirements.	Section 6.15 Section 6.16

Table 2
Summary of the HFE Analysis and V&V Results for the Twelve Elements in NUREG-0711

HFE Element #	HFE Element Topic	Corresponding LGS HFE Program Plan Section	Results Summary Reports (RSRs)	Key Conclusions
1	HFE Program Management	Entire document	N/A	N/A
2	Operating Experience Review	Section 6.4	INL/RPT-22-68703, "Human Factors Engineering Operating Experience Review of the Constellation Limerick Control Room Upgrade: Results Summary Report" (not included in this attachment)	• Many issues identified have direct relevance for most subsequent HFE elements. • Design decisions, such as display locations, are influenced by how the operators interact with each other. • Use of automation in the control room and its implications for human performance, situation awareness, teamwork, etc., is a central issue. Therefore, it is important to observe HFE-related OE issues with automation from various industries and consider these OE when making design decisions. • There is little current OE with automation in the nuclear industry. However, lessons learned in other industries and domains identify important OE. • Some potential control room changes that may affect human performance, including large overview displays, electronic presentation of procedures, new alarm presentation technologies, graphical and interactive displays, and new control room arrangements, are not included in the OER study because little experience related to their problematic and beneficial performance issues is available.

LGS Digital Modernization Project
Application of Human Factors Engineering Principles

3	Functional Requirements Analysis & Function Allocation	Section 6.5	INL/RPT-22-68995, "Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report, Section 4 (included in this attachment)	• Operator actions often occur in parallel. • There is more than one way to achieve successful outcomes. • “Flat topology” of indications/controls is leveraged. The new HSI design needs to support/augment the existing HSI “flat topology.” • The new HSIs provided by the project need to maintain/enhance the existing concept of operations to avoid excessive retraining. • Optimal operator performance is inhibited by the dispersed layout of existing controls and indications. For some manual tasks, operators must remain stationary at the control board, which inhibits situation awareness. • Current design provides minimal trending data. The upgraded design needs to address this issue.
4	Task Analysis	Section 6.6	INL/RPT-22-68995, Section 5	• Specific tasks requiring manual actions could be properly performed using the proposed design concepts • PPS and DCS VDUs need to be grouped together to facilitate coordinated use. • The VDUs need to be located and mounted to support efficient and coordinated controls. They need to support touch screen and pointing device functionality. • Additional evaluations need to occur to determine which variables need to be continuously viewable versus continuously available. • A subset of DCS displays used by the RO should be replicated for the SRO for situation awareness. • Operators will perform additional actions previously performed outside of the control room, which increases workload. This will speed up response to events. • The new MCR design reduces operator movements by consolidating information to the VDUs. • The current use of the control room wall panel provides control room operators with significant operation awareness that supports a common mental model at a distance.

LGS Digital Modernization Project
Application of Human Factors Engineering Principles

5	Staffing and Qualifications	Section 6.7	INL/RPT-22-68995, Section 6	• MCR operator staffing levels are not expected to be modified. • MCR operator qualification requirements are not expected to change. • It is expected that plant procedures will be impacted and that personnel will need to be trained on the characteristics of new system functions and capabilities.
6	Treatment of Important Human Actions	Section 6.8	INL/RPT-22-68995, Section 5.4	• The notional HSI functionality as presented for each scenario would either not negatively impact or improve operator response for these tasks. • Important HAs will be iteratively addressed during the design and V&V phases.
7	Human-System Interface Design	Sections 6.10, 6.11, and 6.12	• Conceptual Verification Report: Feb. 9, 2023; • Preliminary Validation Report: Mar. 30 2023	• The confirmation that the HSI design meets the necessary requirements will be documented in the V&V reports. • Conceptual Verification, Preliminary Verification, and Integrated System Validation will be performed after initial LAR submittal.
8	Procedure Development	Section 6.13	INL/RPT-22-68995, Section 6	• Procedures will be updated after initial LAR submittal. • Procedure changes will be supported by the analyses used to develop the HSIs and the training program for this upgrade. • Procedure changes will address all personnel tasks affected by the changes in the plant systems and HSIs.
9	Training Program Development	Section 6.14	INL/RPT-22-68995, Section 6	• The training program will be updated after initial LAR submittal. • Training program changes will address all personnel tasks affected by the changes in plant systems and HSIs.
10	Human Factors Verification and Validation	Sections 6.9, 6.15, and 6.16	INL/RPT-22-68995 Section 7	• Conceptual Verification, Preliminary Verification, and Integrated System Validation will be performed after initial LAR submittal.
11	Design Implementation	Section 6.15 and Table 6	N/A	• Detailed Integrated System Validation Execution Plan will be performed after initial LAR submittal.
12	Human Performance Monitoring	Section 6.17	N/A	• The CEG human performance monitoring program will provide reasonable assurance that the confidence developed by completing a thorough HFE Program, culminating with the V&V of the control room and integrated systems design is maintained over time.

INL/RPT-22-68693

Human Factors Engineering Program Plan for Constellation Safety Related Instrumentation and Control Upgrades

July 2022

Jeffrey C. Joe
Senior Human Factors Scientist

Paul J. Hunton
Senior Research Scientist

Casey R. Kovesdi
Human Factors Scientist

Idaho National Laboratory

INL is a U.S. Department of Energy National Laboratory operated by Battelle Energy Alliance, LLC

INL/RPT-22-68693

Human Factors Engineering Program Plan for Constellation Safety Related Instrumentation and Control Upgrades

Jeffrey C. Joe
Senior Human Factors Scientist
Paul J. Hunton
Senior Research Scientist
Casey R. Kovesdi
Human Factors Scientist

July 2022

Idaho National Laboratory
Nuclear Science and Technology
Idaho Falls, Idaho 83415

http://www.inl.gov

Prepared for Exelon Generation
Under Cooperative Research and Development Agreement 21CRA5

ABSTRACT

This document presents a NUREG-0711-based Human Factors Engineering Program Plan for use by Constellation Energy (Constellation) as it pertains to the safety-related instrumentation and control upgrades and associated Main Control Room modifications being performed at the Limerick Generating Station. This plan follows a graded approach as allowed by NUREG-0711.

While this plan is specific regarding its application, the methodology presented herein is generic. Constellation may choose to use this Human Factors Engineering Program Plan as a model for future instrumentation and control and associated Main Control Room upgrades at the Limerick Generating Station and at other nuclear power plants within its fleet.

Page intentionally left blank

CONTENTS

FIGURES

TABLES

ACRONYMS

BISI	Bypassed and Inoperable Status Indication
DCRDR	Detailed Control Room Design Review
DCS	Distributed Control System
DEG	Digital Engineering Guide
ESFAS	Engineered Safety Feature Actuation System
EPRI	Electrical Power Research Institute
EPU	Extended Power Uprate
FRA & FA	Functional Requirements Analysis and Function Allocation
FSAR	Final Safety Analysis Report
HA	Human Action
HED	Human Engineering Deficiency
HF	Human Factors
HFE	Human Factors Engineering
HFITS	Human Factors Engineering Issues Tracking System
HRA	Human Reliability Analysis
HSI	Human-System Interface
HTA	Hierarchical Task Analysis
INL	Idaho National Laboratory
I&C	Instrumentation and Control
ISV	Integrated System Validation
KPI	Key Performance Indicator
LER	Licensee Event Report
LGS	Limerick Generating Station
LWR	Light-Water Reactor
MCR	Main Control Room
NPP	Nuclear Power Plant
NRC	Nuclear Regulatory Commission
OE	Operating Experience
OER	Operating Experience Review
OSA	Operational Sequence Analysis
OSD	Operational Sequence Diagram
PAMS	Post-Accident Monitoring System
PPC	Plant Process Computer

PPS	Plant Protection System
PRA	Probabilistic Risk Assessment
RPS	Reactor Protection System
RRCS	Redundant Reactivity Control System
SDP	Standard Design Change Process
SER	Safety Evaluation Report
SPDS	Safety Parameter Display System
SSC	Structure System or Component
TA	Task Analysis
TCS	Turbine Control System
TMI	Three-Mile Island
UFSAR	Updated Final Safety Analysis Report
V&V	Verification and Validation
VDU	Video Display Unit

Human Factors Engineering Program Plan for Constellation Safety Related Instrumentation and Control Upgrades

1. INTRODUCTION AND OVERVIEW

This document represents the Human Factors Engineering (HFE) Plan to be used by Constellation as it modernizes instrumentation and control (I&C) systems in the Limerick Generating Station (LGS) as part of its safety-related I&C upgrade project. The Main Control Room (MCR) as well as local human-system interfaces (HSIs) will be impacted by this upgrade. While this plan is specific regarding its application, the methodology presented herein is generic. Constellation may choose to use this HFE Program Plan as a model for future I&C and associated MCR upgrades at the LGS and other nuclear power plants within its fleet.

This plan applies an appropriate level of HFE to changes affecting both the safety and non-safety I&C modifications scoped within the SR I&C upgrade project, reflecting the importance of HFE to plant reliability, safety, and economic operation. A graded approach is applied that is intended to support the project design objectives while meeting regulatory requirements and expectations to ensure a high level of plant safety and reliability is maintained as changes are made that impact HFE related activities.

The HFE phases discussed in this document are described in the U.S. Nuclear Regulatory Commission's (NRC) "Human Factors Engineering Program Review Model," NUREG-0711, Revision 3, published November 2012 [1]. Each phase (see Figure 1) consists of one or more elements. Each element as presented in Reference [1] contains a description of the review criteria applied by the NRC HFE staff to assess the acceptability of an applicant's submittal regarding safe plant operation.

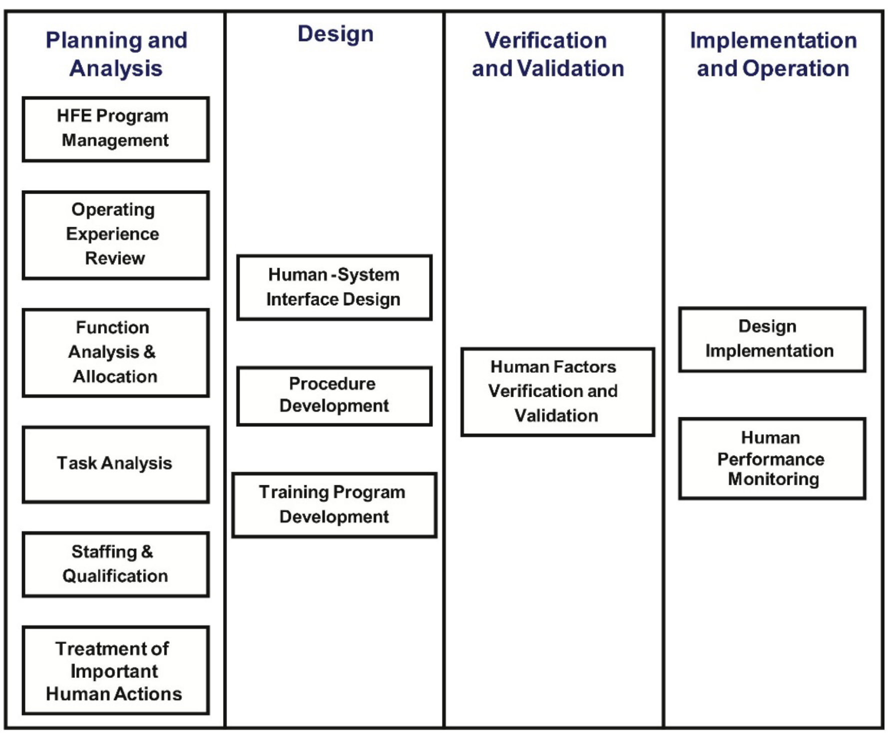


Figure 1. HFE phases covered in NUREG-0711, Rev. 3.

This HFE Program Plan provides guidance regarding all 12 elements described in NUREG-0711 [1] and includes industry best practices.

Several generic sources were reviewed as part of developing this plan. These include:

- NUREG-0711 [1]
- EPRI report 3002004310, "Human Factors Guidance for Control Room and Digital Human-System Interface Design and Modification: Guidelines for Planning, Specification, Design, Licensing, Implementation, Training, Operation, and Maintenance for Operating Plants and New Builds" [2]
- A research report entitled "Development of a Site HFE Program" [3], based upon EPRI research that provides a description of a nuclear power plant (NPP) site HFE Program
- EPRI report 300200319, "HFE Training Course for Operating Nuclear Power Plant Personnel" [4]
- EPRI report, 3002011816, "Digital Engineering Guide (DEG): Decision Making Using Systems Engineering" [12].

These were augmented by the following, project-specific documents and other NRC guidance applicable to SR I&C upgrade project, including:

- AP1000 Interface Specification for Class 1E DC Motor Operated Valves (APP-GW-J4-003) [13]
- AP1000 Protection and Safety Monitoring System - Technical Manual (APP-PMS-J0M-003, Rev. 2) [14]
- Human Factor Engineering Detailed Design Review In-Process Audit [15]
- Limerick Generating Station Unit 1 & 2 Turbine Control System Upgrade Display Design Functional Requirements & Implementation Guidelines (WNA-DS-02820-GLIM, Rev. 1) [16]
- Global Instrumentation & Controls Control & Information Systems Engineering Human-System Interface Display Implementation Guidelines (WNA-DS-04213-GEN, Rev. 1) [17]
- Human Factors Engineering Guideline for the Common Q Display System (WNA-IG-00871-GEN, Rev. 0) [18]
- Guidance for the Review of Changes to Human Actions (NUREG-1764) [6]
- Demonstrating the Feasibility and Reliability of Operator Manual Actions in Response to Fire (NUREG-1852) [19]
- AP1000 Human-System Interface Design Guidelines (APP-OCS-J1-002, Rev. 9) [26].

It is expected that these documents, and others identified as each NUREG-0711 element is accomplished, will provide context-specific information as necessary to support the SR I&C upgrade project.

The remaining sections in this Plan are:

6. HUMAN FACTORS ENGINEERING ACTIVITIES

6.1 Human Factors Engineering Program Management

6.2 New State Vision for Instrumentation and Control Upgrades*

6.3 Concept of Operations*

6.4 Operating Experience Review

6.5 Functional Requirements Analysis and Function Allocation

6.6 Project Screening and Task Analysis

6.7 Staffing and Qualification Analysis

6.8 Important Human Actions

6.9 Verification and Validation: Simulator Strategy*

6.10 Human-System Interface Style Guide

6.11 Conceptual Design Human-System Interface Display and Navigation Strategy*

6.12 Vendor Human-System Interface Design, Oversight, and Human Factors Engineering Issues Tracking

6.13 Evaluation of Impacts to Procedures

6.14 Evaluation of Impacts to Training

6.15 Verification and Validation: Detailed Execution Plan for Integrated System Validation

6.16 Human Factors Verification and Validation

6.17 Human Performance Monitoring

7. SECOND UNIT DELTA ANALYSIS

8. REFERENCES

Section 6 includes additional activities (denoted with an * above) that are not specifically called out in NUREG-0711 but complement the NUREG-0711 elements.

A graded approach to NUREG-0711, as applied to this HFE Program Plan, includes the disposition of NUREG-0711 items/activities associated with element completion in a manner consistent with IEEE-1023, “Recommended Practice for the Application of Human Factors Engineering to Systems, Equipment, and Facilities of Nuclear Power Generating Stations and Other Nuclear Facilities,” [10] by either:

- Applying a NUREG-0711 item or activity to the upgraded I&C/HFE design as deemed appropriate and practicable
- Performing similar or alternate activities that meet the intent of the item or activity identified in NUREG-0711
- Justifying why a NUREG-0711 item or activity is not applicable or otherwise not being performed as part of the HFE effort.

NUREG-0711 is being used as a tool to develop the LGS HFE Program Plan and identify the pertinent HFE activities to perform for the project. LGS is obligated to meet their regulatory and license basis HFE requirements, which are most explicitly defined in:

- Generic Letter 82-33 (NUREG-0737 Supplement 1) [28]
- The Limerick UFSAR Section 1.13 [29]
- Detailed Control Room Design Review (DCRDR) program plan [30], the initial Limerick Plant Control Room Design Review Final Report [31], and associated supplemental reports [32] and [33].

The conclusions in the NRC's SER for the LGS LAR are to be based on these requirements.

While this HFE Program Plan provides guidance for the design organization on all 12 NUREG-0711 elements, not all 12 HFE elements strictly relate to the requirements in NUREG-0737 Supplement 1, Item I.D.1. The additional HFE activities performed per NUREG-0711, Revision 3 for the SSCs and procedures affected by the LGS Modernization Project, beyond those required by NUREG-0737 Supplement 1, Item I.D.1, only expands the LGS HFE licensing basis for those specific SSCs and procedures.

2. BACKGROUND

NPP personnel play a vital role in the productive, efficient, and safe generation of power. Operators monitor and control the plant to ensure it is functioning properly. Personnel performance and resulting plant performance are influenced by many aspects of plant design, including the level of automation and the interfaces provided for personnel to interact with the plant. The latter are referred to as HSIs and include resources such as alarms, displays, and controls located in the MCR and numerous local control stations situated throughout the plant.

Constellation is modernizing Limerick SR I&C systems and associated HSIs There are many reasons for modernization, including:

1. Addressing obsolescence and lack of spare parts
2. Meeting the need for equipment replacement due to high maintenance cost or lack of vendor support for existing equipment
3. Implementing new functionality necessary for adding beneficial capabilities and reduce replacement system lifecycle costs (e.g., automate control functions, reduce or eliminate surveillances associated with legacy equipment)
4. Improving plant performance, HSI functionality, and reliability
5. Enhancing operator performance and reliability.

These modifications can affect personnel in various ways. They can impact the role of personnel, the tasks to be performed, and the way their tasks are performed. As part of modernization, HSIs are becoming more computer-based, incorporating features such as a greater use of automation, graphic presentation of information, extensive information available by paging, soft controls, and touchscreen interfaces.

The potential benefits of modernization are compelling and will result in more efficient operations and maintenance, leading to improved power plant availability and safety through the avoidance of transients, forced outages, equipment damage, and unnecessary shutdowns. Other potential benefits also include increased efficiency and power output as well as reduced operating costs.

New digital systems provide the opportunity to give personnel information they did not have with legacy systems. Improved instrumentation and signal validation techniques can help ensure that the information is more accurate, precise, and reliable. In addition, data processing techniques and the flexibility of computer-based information presentation enable designers to present information in ways that are much better suited to personnel tasks and information processing needs to achieve more efficient, cost-effective power production.

While plant modernization can greatly improve personnel and plant performance, it is important to recognize that, if poorly designed and implemented, there is a potential to negatively impact performance, increase errors, and reduce human reliability, resulting in a detrimental effect on safety and cost-effective power production. HFE is needed to ensure that the benefits of the new technology are realized and that problems with its implementation are minimized.

The guidance provided in this document will help Constellation recognize the positive potential impacts identified above by ensuring design and implementation efforts address the important human factors aspects for the Limerick SR I&C upgrade project.

By leveraging this HFE Program and related products as developed for the Limerick SR I&C upgrade project as a foundation for performing similar I&C upgrades in the future, Constellation will drive more consistent HSI implementations to further advance improved reliability along with improved efficient operations and maintenance.

3. HFE PROGRAM PLAN OBJECTIVES

The objectives of this HFE Program Plan are to provide:

- Specific HFE guidance to inform Limerick SR I&C upgrade project activities impacting control rooms, related facilities, and HSIs to satisfy regulatory requirements and expectations. The following sections of this plan provide this guidance following the structure and information provided in NUREG-0711 [1].
- An HFE Program Plan that Constellation can leverage in the future to ensure safe and reliable plant operation meeting human performance expectations as additional plant modifications are made over time.

4. HFE AS INTEGRAL PART OF THE MODERNIZATION PROCESS

It is important that HFE be an integral part of the modification engineering process and not be performed as a separate or standalone activity. HFE personnel must be aware and take advantage of activities that are being performed as part of other related engineering modification efforts. Likewise, results from HFE studies and analyses must be made available to other groups to meet their information needs. For example, I&C design engineers, operations personnel, and HFE subject matter experts need to work together to allocate functions between automatic and manual control and design the HSIs to support operator monitoring and control tasks.

In Figure 2, the HFE process presented in NUREG-0711 [1] from Figure 1 is superimposed in red upon the systems engineering “VEE” diagram taken from the EPRI DEG [12]. This is consistent with the HFE design guidance contained in the EPRI DEG. The EPRI guidance considers both safety and availability concerns.

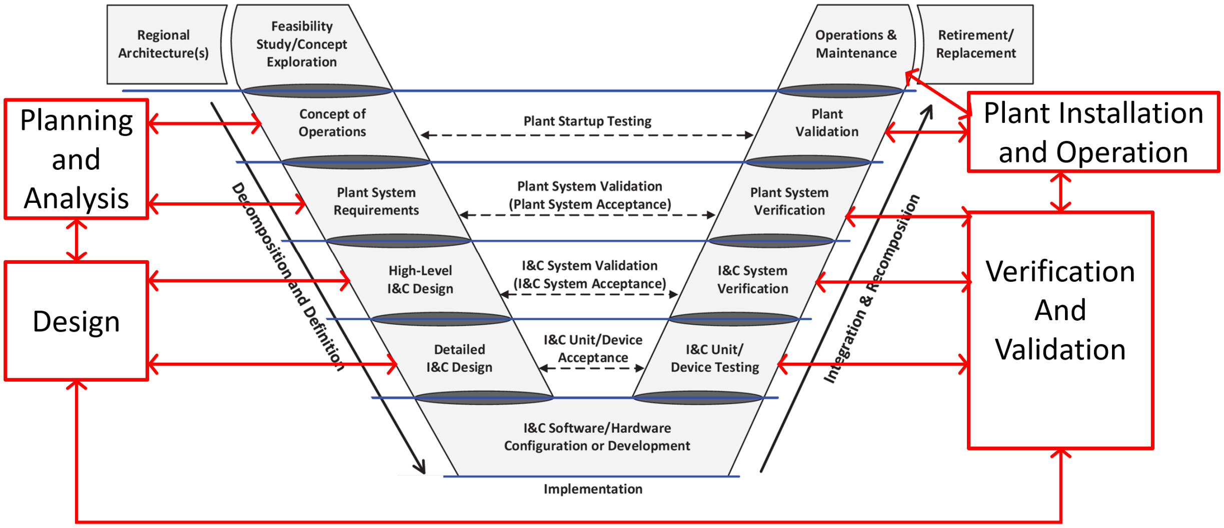


Figure 2. Relationship between Systems Engineering and NUREG-0711 HFE Program Phases.

The application of the EPRI DEG by utilities in the United States is directed through Nuclear Energy Institute Mandatory Efficiency Bulletin 17-06, "Implement Standard Design Change Process" [20]. This bulletin establishes a standard design change process (IP-ENG-001) [21] for the industry. NISP EN-04, "Standard Digital Engineering Process," [22] has been issued as a supplemental SDP under the same bulletin. NISP-EN-04 states that the EPRI DEG is to be used in conjunction with IP-ENG-001 for design changes involving digital equipment.

Figure 3 shows how HFE should be integrated with other site modernization activities. The figure illustrates some of the more important activities that interact with HFE. Figure 3 shows the HFE Program at the center of the modernization activities. This is simply to show that HFE interacts with many other activities. It does not suggest that HFE is the most important or that other activities revolve around HFE.

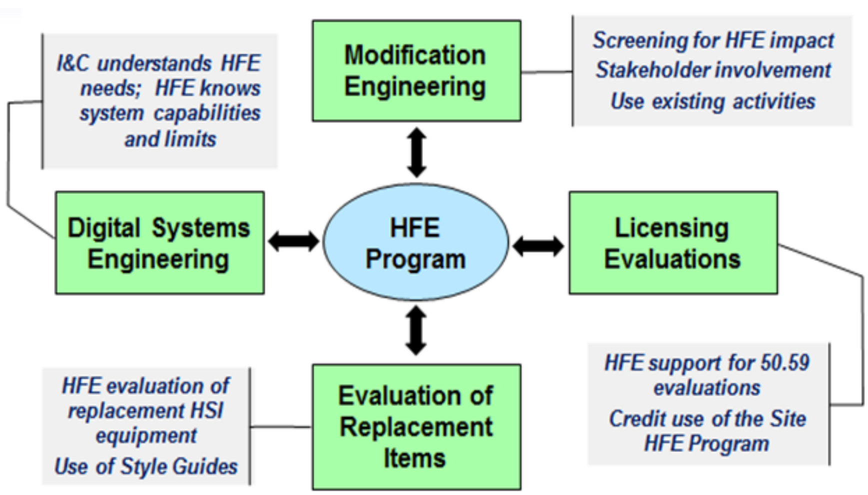


Figure 3. Major activities integrated with HFE (not all activities shown) [4].

5. SUMMARY OF LIMERICK SAFETY-RELATED INSTRUMENTATION AND CONTROL HUMAN FACTORS ENGINEERING ACTIVITIES

Table 1 provides a detailed summary list of Limerick SR I&C upgrade project HFE design-related activities performed during each design modification phase as presented therein Table 1. Description of individual activities for each design modification phase are provided in the sections that follow in this document. These descriptions can be directly accessed by clicking on the document section number listed for each activity in Table 1.

Table 1. Summary of NUREG-0711 activities and their relationship to project HFE activities (applicable NUREG-0711 elements identified).

Activity (and associated NUREG-0711 section)	Document Section that Addresses This Activity
Planning and Analysis Phase	
HFE Program Management (NUREG-0711, Section 2)	Section 6.1
"New State" Vision for I&C Upgrades (no specific reference in NUREG-0711)	Section 6.2
Concept of Operations (CONOPS) (NUREG-0711, Glossary)	Section 6.3
Operating Experience Review (OER) (NUREG-0711, Section 3)	Section 6.4
Functional Requirements Analysis and Function Allocation (FRA & FA) (NUREG-0711, Section 4)	Section 6.5
Project Screening and Task Analysis (TA) (NUREG-0711, Section 5)	Section 6.6
Staffing and Qualification Analysis (NUREG-0711, Section 6)	Section 6.7
Important Human Actions (NUREG-0711, Section 7)	Section 6.8
Verification & Validation: Establish Simulator strategy to support Integrated System Validation (ISV) (NUREG-0711, Section 11)	Section 6.9
HSI Style Guide (NUREG-0711, Section 8.4.3)	Section 6.10
Conceptual Design HSI Display & Navigation Strategy (NUREG-0711, Section 8)	Section 6.11
Design Phase	
Vendor Human-System Interface Design, Oversight, and Human Factors Engineering Issue Tracking (NUREG-0711, Section 12)	Section 6.12
Evaluate Impacts to Procedures (NUREG-0711, Section 9)	Section 6.13
Evaluate Impacts to Training (NUREG-0711, Section 10)	Section 6.14
Verification and Validation: Establish ISV Detailed Execution Plan (NUREG-0711, Section 11)	Section 6.15

Activity (and associated NUREG-0711 section)	Document Section that Addresses This Activity
Verification and Validation Phase	
HSI Design Verification (NUREG-0711 Section 11)	Section 6.16.1
Perform ISV and Produce Report (NUREG-0711 Section 11)	Section 6.16.2
Installation and Operation	
Human Performance Monitoring (NUREG-0711 Section 13)	Section 6.17

6. HUMAN FACTORS ENGINEERING ACTIVITIES

6.1 Human Factors Engineering Program Management

This HFE Program Plan provides a systematic method integrating HFE into plant analysis, design, evaluation, and implementation to achieve safe, efficient, and reliable operation, maintenance, testing, inspection, and surveillance of the plant. NUREG-0711 [1] is used as a guide to achieve this end. Related goals include to:

- Ensure personnel can perform tasks (particularly important HAs) within the established safety, time, and performance criteria with the HSIs provided
- Support a design that maintains operator vigilance and supports situation awareness, including addressing operating procedures, training, staffing levels, and qualifications
- Provide acceptable workload levels for operators
- Provide a design that helps prevent operator error and provides for error prevention, detection, and recovery capability
- Coordinate and integrate HFE activities with relevant engineering activities ensuring application of HFE principles and guidelines in design and verification.

The HFE Design Team, its authority, and its location within the Limerick SR I&C upgrade project organization are defined below.

1. The Limerick SR I&C upgrade Project Manager as assisted by the assigned Responsible Engineer for the Engineering Change are ultimately responsible to ensure that HFE is properly addressed during project execution through project closeout.
2. The Project Manager as assisted by the assigned Responsible Engineer shall name the HFE Team Leader and the HFE Design Team members to conduct the HFE activities associated with the Engineering Change. NUREG-0711 Rev. 3 Appendix A shall be used as a guide for individuals to be included in the HFE Design Team.

3. The HFE Design Team is accountable to the Responsible Engineer for the Engineering Change and coordinates its activities with the Engineering Change Team. The responsibilities of the HFE Design Team are listed below:
   A. HFE Design Team Leader – Responsible for overall direction to the development and conduct of the HFE Program Management Implementation Plan
   B. HFE Design Team – Responsible for:
      – Developing all HFE plans, procedures, and reports identified in this HFE Program Plan
   C. Overseeing and reviewing all activities in HFE design, development, test, and evaluation, including the initiation, recommendation, and provision of solutions through designated channels for problems identified in implementing the HFE work
      – Verifying that the team's recommendations are implemented
      – Assuring that all HFE activities comply with the HFE plans and procedures
      – Preparing budgets and scheduling work and milestones
   D. Human Factors Engineer – As a member of the HFE Design Team, provides human factors knowledge and expertise in applying the criteria of the HFE graded approach and the development of the specific HFE Program Plan identified deliverables. The HFE Design Team Leader may be a Human Factors Engineer and also serve as a team member, but this is not a requirement.
   E. I&C or Digital Engineer – As a member of the HFE Design Team, provides expertise on the control room design and licensing basis, I&C system specifications, engineering and design criteria, and HSI capabilities and limitations.
   F. Plant Operators – As members of the HFE Design Team, provide knowledge of the control room conduct of operations protocols, operator procedures, and human performance expectations for operators. Operators are also expected to provide relevant operator experience information to help identify HFE design attributes that will enhance plant and human performance for consideration of both the HFE Team and the Design Team. A minimum of two operators are recommended for the HFE Design Team.
   G. I&C/HSI Vendor Engineer(s) – The selected I&C vendor brings a wealth of knowledge with regard to the HSI capabilities and control functions the platform(s) they are contracted to provide can support. The vendor will communicate these capabilities and Vendor Engineers will work with the rest of the HFE Design Team to apply them.
   H. Additional team members may be required depending on the nature of the modification. This may include a Design Engineer, Systems Engineer, and a Probabilistic Risk Assessment/Human Reliability Assessment expert if human actions impact the licensing basis. In some cases, a training expert may be needed if the modification involves new or changed skills, possibly due to the increased use of automation. Team membership will be periodically reassessed to ensure its composition is appropriate.
4. The HFE Design Team shall prepare a budget, schedule, and milestones for the selected HFE elements in the format prescribed by the Constellation Engineering Change process.
5. The HFE Design Team, with the support of other engineering staff, shall identify the HSI design activities using a graded approach analysis and manage those activities through final validation of the implemented design.
6. The HFE Design Team shall conduct, oversee, and review all selected elements for the HFE design, development, test, and evaluation, including the initiation, recommendation, and provision of solutions through designated channels for problems identified in implementing the HFE work.

7. The HFE Design Team shall verify that HFE recommendations are dispositioned. For those that are not implemented, the justification for not implementing them shall be technically sound and properly documented.
8. The HFE Design Team shall prepare technical reports that address HFE elements as studies and analyses for each element are completed.

HFE Design Team members are identified, and the resumes are kept on file by the Project Manager.

The HFE Program activities described in subsequent sections represent a living program that extends throughout the lifecycle of the modernized facilities.

6.2 New State Vision for Instrumentation and Control Upgrades

It needs to be understood that, in addition to performing the SR I&C upgrade project, Constellation is planning future digital upgrades and associated MCR upgrades to address obsolescence and improve plant and human performance, while lowering plant total ownership costs. To support both near- and long-term objectives, the Limerick SR I&C upgrade project will be performed in such a way that it:

- Stands alone so that, when the upgrade is completed, it functions in harmony with rest of the plant and MCR at that point in time
- Can be leveraged with no or minor additional modifications to complement a larger set of future digital and MCR upgrades.

A New State vision as described in the combined Functional Requirements Analysis and Function Allocation (FRA & FA) and Task Analysis (TA) report will describe items such as:

- Specific design tenets and attributes for the Limerick SR I&C upgrade project. An example design tenant is that the HSI Style Guide for this project will leverage the native capabilities of the graphics packages of the platforms selected by Constellation to perform this upgrade to the maximum extent practicable. The HSI Style Guide will also establish standard methodologies to harmonize graphical user interface attributes (e.g., colors and navigation). This will ideally eliminate the need for custom software coding of graphical displays. This:
  - Promotes the standardization of displays developed for this project
  - Supports the long-term lifecycle management of the display graphics. Graphics generated using standard vendor tools are much more likely to be "harvestable" intellectual property should platform hardware and utility software become obsolete and need to be upgraded
  - Establish a foundation for standardizing potential future modifications to displays developed for this project and the development of displays for future projects that leverage the platforms installed by the Limerick SR I&C upgrade project
- A notional 3D model and associated text description of the MCR depicting the Limerick SR I&C upgrade project as implemented, which will be used as a guide for MCR modifications for this upgrade and will be iterated during the design process, resulting in an "as built" 3D layout when this project is completed that must stand alone when the upgrade is completed.

Project attributes that support of the New State Vision will be discussed and are directly related to a parallel formulation of a Concept of Operations as presented in Section 6.3 below

6.3 Concept of Operations

The concept of operations is a major consideration in deciding how to allocate functions. The description of concept of operations provided in the EPRI HFE guidelines [2] as adapted for this project is provided below.

The concept of operations defines the desired role for personnel. It is influenced by several considerations, including the New State vision and the Operating Experience Review (OER) (see Figure 4). For example, changing the level of automation may be one of the design goals of the plant modification. Automation may be one way of accomplishing goals such as:

- Increasing some aspect of efficiency or productivity (e.g., to reduce system startup time)
- Eliminating or minimizing difficult or time-consuming tasks
- Eliminating or minimizing the opportunity for human error related to some task or operation identified in the OER as problematic
- Changing staffing responsibilities, for example to move the operators' responsibilities to more of a supervisory role or to perform normal control room operations with fewer operators (may not be possible because of regulatory requirements but may be possible to reduce the number of auxiliary or equipment operators).

As Constellation executes the design process, the HFE Team will become more informed as to available capabilities offered by the upgrade and how their application can impact the concept of operations. It is expected that the formulation/refinement of both the concept of operations and the HSI design will be iterative.

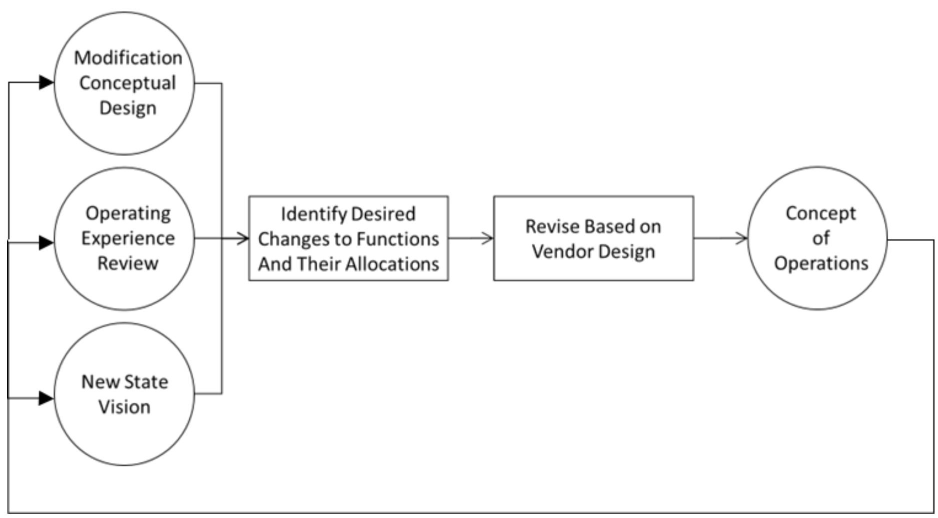


Figure 4. Development of a Concept of Operations.

The concept of operations for the Limerick SR I&C upgrade project (along with the final project MCR layout as discussed in Section 6.2) must stand alone in that, when the upgrade is completed, it performs in harmony with rest of the plant and the MCR at that point in time.

While not a direct product of Limerick SR I&C upgrade project, it is envisioned that the concept of operations developed for this project for the will inform and promote achieving the New State Vison through potential future modifications.

6.4 Operating Experience Review

Objective. The main objective of conducting an OER is to identify HFE-related safety and availability issues and lessons learned that can be applied in designing, analyzing, and evaluating the modification. The OER provides information on the performance of predecessor designs, such as the earlier designs on which the modification is based. The issues and lessons learned from operating experience provide a basis to improve the modernization and thus the plant's design at the beginning and during the modification process. An OER will support avoiding the negative features of predecessor designs, while retaining positive features.

Methodology. The methodology applied is based on NUREG-0711 [1] review criteria and guidance in EPRI 3002004310 [2].

The OER is limited to identifying and analyzing operating experience related to the events, scenarios, equipment, and systems involving the planned modernization effort. The OER results will be applied to activities associated with the FRA & FA and TA elements. Some of the issues identified during the OER are applicable to subsequent elements in the design process, such as HSI design and HFE verification and validation (V&V).

The OER involves obtaining and analyzing HFE-related safety and availability issues and information related to the modernization effort. It is important to create a list of HFE OER search terms and make them available to those responsible for performing the OE searches. Also, a lead individual should be identified as having responsibility for reviewing each source. Some of the sources to consider include:

1. Related plants and systems, including all Constellation NPPs, domestic NPPs, and international NPPs, if OE from these other sources is determined to be relevant to the modernization effort.
2. Vendors, consultants, and system suppliers that may be providing services or equipment related to the modernization effort.
3. Recognized industry HFE issues identified in NUREG/CR-6400 [7] and the 14 Volumes in NUREG-1275 [8], with special attention given to Volumes 8 and 11.
4. Related HFE technology from other industries (e.g., aviation) that is new with the modernization effort (e.g., automation).
5. Issues identified by Limerick control room personnel by interviews and surveys.
6. Risk-important HAs that are different or where errors have occurred.

The OER methodology is shown in Figure 5. The OE sources shown above will be reviewed, as shown in the left two boxes in Figure 5.

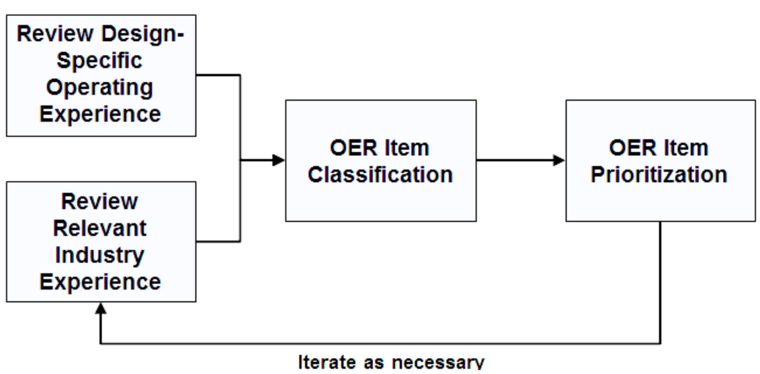


Figure 5. OER methodology.

These results will be analyzed, and relevant items classified according to the element with which each was associated, as shown in Table 2.

Table 2. Relation between HFE elements and item classification.

HFE Element	OER Item Classification
Functional Analysis and Function Allocation	Basis for initial requirements
	Basis for initial allocations
	Identification of need for modifications
Task Analysis, Human Reliability Analysis, and Staffing/Qualifications	Important human actions and errors
	Problematic operations and tasks
	Instances of staffing shortfalls
Human-System Interface (HSI), Procedures, and Training Development	Trade study evaluations
	Potential design solutions
	Potential design issues
Human Factors Verification and Validation	Tasks to be evaluated
	Event and scenario selection
	Performance measure selection
	Issue resolution verification

Each item will be prioritized following the procedure shown in Figure 6. This listing of prioritized items permits tracking the disposition of each item, thus ensuring the knowledge is available to the HFE team. Each issue determined to be relevant to the design, but not yet addressed, will be placed in the issue-tracking system (Section 6.12.3).

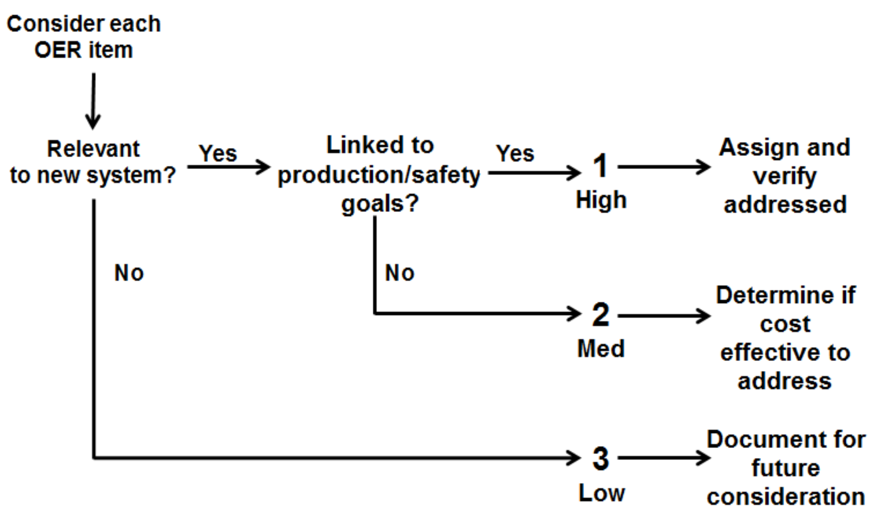


Figure 6. Operator experience review item prioritization method.

Results. An OER technical report will be the output of this activity. It will document the OER results for use by the HFE team and other engineering groups involved in the modernization effort.

6.5 Functional Requirements Analysis and Function Allocation

Function analysis is the assignment of the control and management of functions to personnel (manual control), automatic systems (automated control) and a combination of both (shared control). Taking advantage of functional control capabilities provided by the design modernization and allocating these management functions appropriately between manual and automated control will reduce human errors and inappropriate actions. This will result in higher levels of system safety and economic performance.

The allocation of control functions to either machines or humans can be determined by a number of factors, such as:

- Technology capability and limitations (i.e., technical feasibility)
- Human capability and limitations
- Operational requirements
- Nuclear safety requirements
- Equipment protection requirements
- Regulatory requirements
- Organizational requirements
- Cost, productivity, and economic factors.

Guidance for the allocation of control functions is provided in NUREG/CR-3331 [9].

Objectives. The objectives of the FRA & FA element are to identify and define new and changed control functions resulting from the modernization effort required to satisfy plant safety and availability goals and to allocate responsibilities for those functions to personnel and automation in a way that takes advantage of human and automation strengths and avoids human and automation limitations and weaknesses.

Methodology. The FRA & FA methodology is based upon the principles described in NUREG-0711 [1], Section 3.3 of an EPRI report providing HFE guidance for control room design and modification [2], IEEE-1023 providing recommendations for applying HFE [10], and an EPRI HFE training course [4]. A graded approach should be followed so only FRA & FA activities needed for the modification are performed. A major benefit of applying the graded approach is the elimination of unnecessary work with the assurance that all necessary HFE activities are complete.

Any new system functions added along with any changes to existing functions made by the Limerick SR I&C upgrade project modification will be identified by Constellation. Also, any changes in the allocation of the management of functions to personnel or automated systems (i.e., changes in the level of automation) will be identified. The reason is that changes in the control of functions and allocations may impact the conceptual design and the roles, responsibilities, and workload of personnel. FRA & FA methods are applied to identify new and changed functions and allocate them between automation and personnel.

Functions that are addressed in these evaluations should include not only process control and protection functions, but also other required functions such as collecting data, evaluating or comparing data, tracking parameters over time, calculating values, retrieving needed information displays, and other secondary tasks. Decisions on what automation features to be included will address these functions and their impact on personnel workload and potential for human error. New technology features may provide opportunities to reduce burden on operators and maintenance technicians and improve human performance.

It is important to document the FRA & FA results for use by the HFE Team and other engineering groups involved in the modernization effort. The results will be applied to activities associated with the TA element and to subsequent elements in the design process (e.g., HSI design and HFE V&V).

Section 3.3 of an EPRI HFE guidelines report [2] provides very detailed guidance for performing the FRA & FA effort. The HFE Team performing the FRA & FA should review and apply, as appropriate, the guidance presented in the EPRI document. Figure 7 provides an overview of the FRA & FA process based on Reference [2], Section 3.4.4].

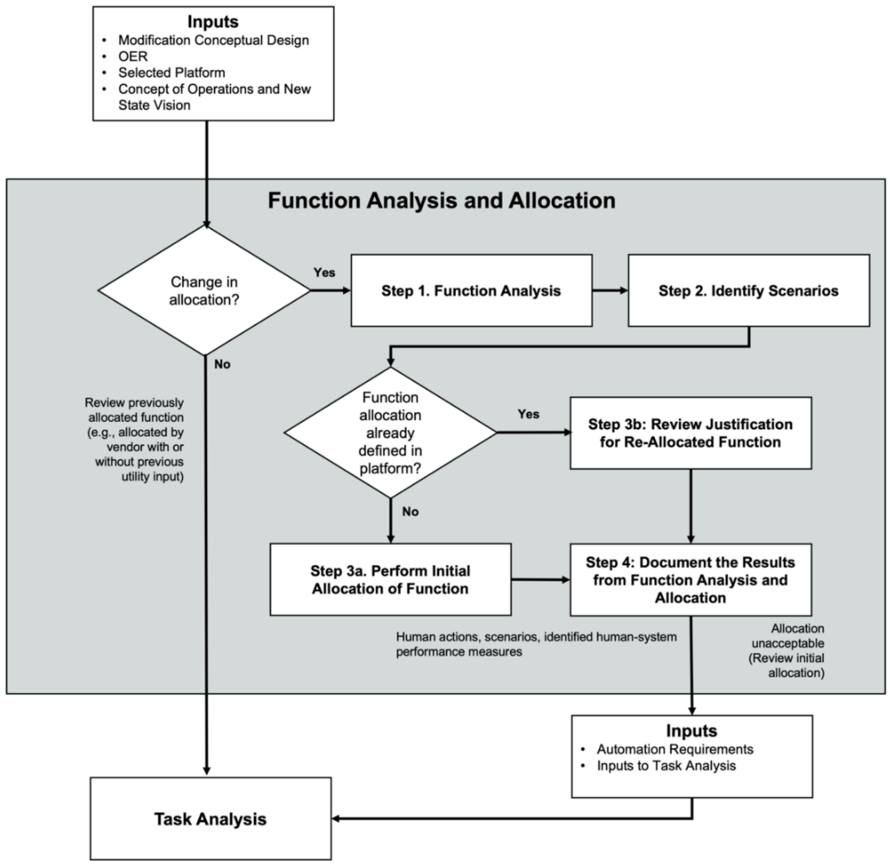


Figure 7. Overview of FRA & FA based on Reference [2].

Input for FRA & FA is from several sources, including the New State Vision for I&C Upgrades in Section 6.2, Concept of Operations in Section 6.3, and OER as described in Section 6.4. The New State Vision and Concept of Operations provide a physical and functional description of the post-modification state, including the use of automation and expected roles and responsibilities that informs FRA & FA. For example, the goals of using automation, such as by eliminating or minimizing difficult or time-consuming tasks, should serve as input into deciding the allocation of function. The OER may identify some troublesome aspects of an automated system that could be addressed by increasing the level of human involvement in the function or task accomplishment. An example is when there are situations where the decision to initiate an automatic sequence cannot be made solely on information available to the automatic control system. The OER may have indicated that an automatic sequence was incorrectly initiated on past occasions. One solution may be to impose a hold at some point in the automatic process to allow time for an operator to control whether the sequence proceeds based on information not available to the automatic system.

There are several methods that may be used to identify new and changed functions and to allocate these functions appropriately. The method described below was used by Idaho National Laboratory (INL) in previous industry modernization efforts involving planning for the replacement of a Turbine Control System (TCS), a TCS and the Plant Process Computer (PPC) modification, and an Extended Power Uprate as supported by INL. Constellation intends to follow a similar approach for the Limerick safety-related I&C upgrade.

Analyses. Analyses were performed to identify major functions that may change from current practices based on expected system changes introduced with the modifications. Document sources reviewed and analyzed, if available, included Engineering Change Notices, modification descriptions included in the display and other Requirements Specifications, License Amendment Requests (for the Extended Power Uprate modifications), and procedures for scenarios expected to be impacted by the modifications. Discussions with engineers involved in the modernization project provided additional information about expected changes.

Planning meeting. A planning meeting was conducted with operators, engineers, and HFE members of the study team involved in the modernization effort. Its objectives were to:

- Identify significant events, scenarios, and procedures impacted by the modernization effort in which functions and operator tasks will change
- Evaluate the large number of events, scenarios, and procedures expected to be identified and select the ones expected to have largest positive and negative impacts on operator and system performance
- Describe the events, scenarios, and procedures in sufficient detail for them to be simulated during the FRA & FA workshop.

Criteria considered during scenario evaluation included:

- Providing the greatest operator error traps and opportunities for human error and poor performance
- Offering the greatest opportunity for improved safety and economic performance
- Involving changes from manual to shared or automatic functions
- Involving the most changes in operator roles and responsibilities
- Involving increased operator workload and reduction in operator action times
- Involving conditions in which OE results showed operator problems.

Events, scenarios, and procedures identified during the planning meeting were further developed and refined prior to the FRA & FA workshop. Operators from the NPPs involved in the modernization effort that participated in the planning meeting were responsible for finalizing the scenarios for their respective plants prior to the workshop.

FRA & FA workshop. A workshop was performed either (1) in an operator training simulator at the NPP where the modernization effort will take place or (2) in a simulator facility with software from the plant providing a dynamic and realistic simulation of the plant's HSIs. The simulation facility permitted control room operators to walk through the scenarios selected during the planning meeting. The walkthroughs represented the conditions found in the control room doing operations. For example, a procedure reader was used where this is the practice at the subject NPP.

During the walkthrough, the simulator was stopped at steps in the procedure where functions may be added, eliminated, or changed due to the modernization effort or allocated differently than at present. The operators and others in attendance were asked to discuss these possible changes from existing practices. This process was followed for the remainder of the scenario and was repeated for other scenarios selected during the planning meeting. At the completion of each scenario, the operators and observers reviewed the identified scenario and functions and the initial allocations made.

Example Method Results. A table was constructed containing the results from the FRA & FA walkthroughs. Table row headings included:

- Scenario description and purpose
- Primary modernization function(s)
- Primary operator role
- Applicable procedure(s)
- Simulator initial conditions
- Operator response
- Observations
- Preliminary function allocation findings
- Summary
- Additional comments and conclusions.

A similar approach to the example above is envisioned.

Results. An FRA & FA technical report will be the output of this planning and analysis activity. It will document the FRA & FA results for use by the HFE team and other engineering groups involved in the modernization effort. The results will be applied to activities associated with the TA element and to subsequent elements in the design process (e.g., HSI design and HFE V&V). The FRA & FA technical report may be combined with the TA technical report.

The FRA & FA results will be reviewed, verified, and possibly modified during subsequent element analyses. For example, the results for this element will be a major input to the TA element, which follows. It may be found during TA that certain allocations need to be revised because of operator workload challenges not identified during the FRA & FA element. In addition, modification features and capabilities may be changed based on further engineering analyses and operator input. For example, it may be found that certain functions previously planned to be assigned to operators can be automated. Such changes may require that part of the FRA & FA be revised or otherwise addressed in other HFE documentation.

6.6 Project Screening and Task Analysis

6.6.1 HUMAN FACTORS ENGINEERING PROJECT SCREENING

The SR I&C upgrade project will be screened to determine the extent of potential HFE impacts. Changes considered in project screening include those that impact operator HSIs inside or outside the MCR or changes to workplaces where operators use HSIs, if the changes could impact human performance. Changes that do not modify HSIs but could have other potential impact on operator tasks are also considered in project screening (e.g., system changes that reduce the amount of time available for an operator to perform a task).

HSIs involved in maintenance activities are considered if their use is related to MCR operations. For example, if a maintenance technician uses an HSI to support troubleshooting and that HSI is also available to a MCR operator to support cooperation between maintenance and operations, activities related to this HSI are within the scope of the HFE Program Plan.

Changes that have potential HFE impact and thus impact project screening can vary widely in scope and extent of change, complexity, safety significance, and importance to plant operation. For example, changes to operator HSIs can range from replacing an analog meter with a digital one, or a minor change to an existing computer display, to an entire system replacement, involving the conversion of analog displays and controls to computer-based workstations. The changes may affect only non-safety, non-critical HSIs and tasks, or they may impact safety-critical HSIs and tasks. The scope of the Limerick SR I&C upgrade project covers the full range of the examples above. The HFE Program Plan addresses project modifications at an appropriate level using as part of HFE project screening and subsequent HFE activities.

A process for screening project modifications as a whole and associated HFE activities is presented in Figure 8. This process based on guidance given in NUREG-0800, Chapter 18 Sections II.B and II.C [5], EPRI 300200319. Sections 2.4.2 and 2.4.3 [2], and by an EPRI report providing a HFE Program to support modifications [3]**.**

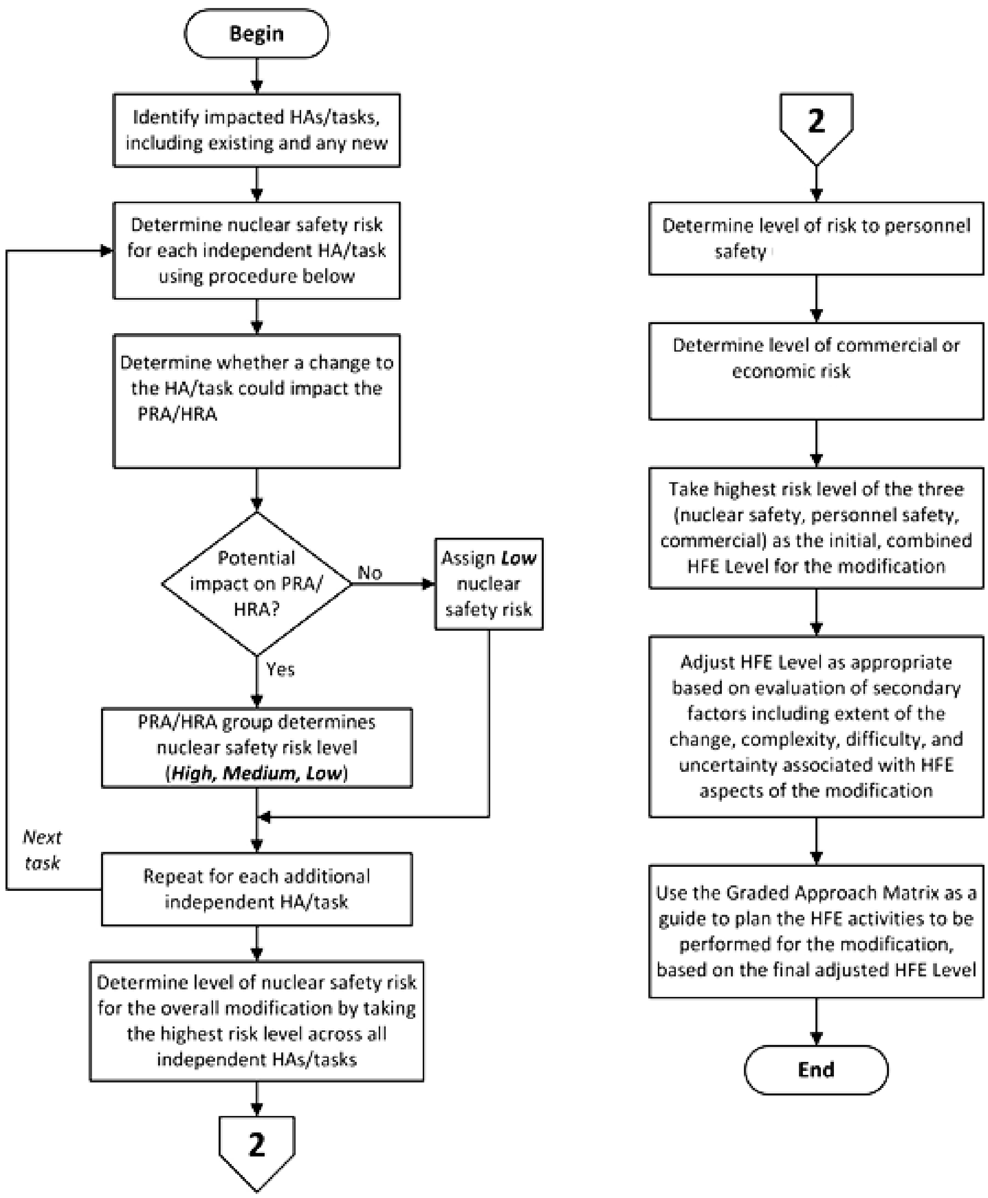


Figure 8. Process for determining HFE level of activity through project screening [3].

Starting at the top-left of Figure 8, important human actions or tasks that may be impacted by the modification are identified. Then, for each important human action or task, the potential nuclear safety risk associated with the task is identified using the Probabilistic Risk Assessment (PRA) and following a risk-informed approach similar to that used by the NRC when reviewing changes to human actions per NUREG-1764 [6]. The intent here is to be thorough in the inclusion, analysis, and treatment of important human actions, but at the same time, not reinvent the wheel with respect to repeating prior analyses (including PRA models) that have already determined certain human actions are not risk significant and are not changing or otherwise affected by modifications to the MCR or its I&C systems. For the Limerick SR I&C upgrade project, the focus of this screening is on the important HAs or tasks impacted or introduced by the design change. These are expected to be limited in in number.

Other risks are then assessed as shown on the top-right side of Figure 8. These include the level of risk introduced by the upgrade to personnel safety, and risk to commercial operation are assessed. Risk to commercial operation considers potential to cause a plant trip or power derating, and potential risk to licensing status (e.g., potential for Licensee Event Reports or impact on key performance indicators).

The three types of risk are then combined on the bottom-right side of Figure 8, taking the highest risk identified in any of the three categories (nuclear safety, personnel safety, economic operation). Table 3 as shown below is then used to set the initial HFE Level for the modification.

Table 3. HFE project screening matrix showing HFE activities based on change level [3].

Type of Change	HFE Activities
Design Modification with HFE Impact (screens into HFE Program)	
Level 1 (High)	Full set of HFE activities and formal documentation per NUREG-0800 Chapter 18 [5] and NUREG-0711 [1]
Level 2 (Medium)	Intermediate level of HFE activities and associated documentation
Level 3 (Low)	HFE activities address all elements of the HFE Program but at a lower level and less formal documentation; typically handled by site HFE team
Operator-Configurable Change, or Maintenance-Configurable Change	No HFE involvement unless requested

Following this, secondary factors are assessed, and the initial project HFE Level may be adjusted up or down by one level as shown in Table 3 based on the secondary factors. These include the scope or extent of the change being made (degree of impact on the system and the task), complexity, uncertainty, difficulty of the task(s) involved, previous experience with the modification, etc. Table 3 guidance is based on guidance from Fink and colleagues [3]:

> *First, all human actions or tasks that may be impacted by the modification are identified. Then, for each action or task, the potential nuclear safety risk associated with the task is identified using the PRA and following a risk-informed approach similar to that used by the NRC when reviewing changes to human actions per NUREG-1764 [6]. Then the level of risk to personnel safety and risk to commercial operation are assessed. Risk to commercial operation considers potential to cause a plant trip or power derating, and potential risk to licensing status – for example, potential for LERs or impact on KPIs. The three types of risk are combined, taking the highest risk identified in any of the three categories (nuclear safety, personnel safety, economic operation). This sets the initial HFE Level for the modification.*

Following this, secondary factors are assessed and the initial HFE Level may be adjusted up or down by one level based on the secondary factors. These include the scope or extent of the change being made (degree of impact on the system and the task), complexity, uncertainty, and difficulty of the task(s) involved. The final adjusted HFE Level is used to determine what HFE activities and associated documentation will be needed for the modification.

Table 3 is only a guide. Some of the HFE elements may not be applicable for a particular modification and do not need to be performed. For example, FRA & FA may not be required for modification elements that do not change any existing or add new functions or tasks, and for which the OER shows no need to modify function allocation or levels of automation. Also, further tailoring within individual HFE activities may be appropriate (e.g., adjusting the level of detail of the TAs performed for tasks of differing importance) or focusing the HFE V&V activities on the tasks or HSIs that are most important. The information developed through the risk assessment should aid in determining how to tailor the individual HFE activities.

Some HSI modifications may provide the capability for operators to configure certain aspects of the HSI according to the operator's needs or preferences at any particular time. An example would be the ability to select what parameters to be included on a trend plot on a computer-generated display. These "changes" are not design changes but are referred to as operator-configurable changes (bottom row in Table 3). The HSI system, along with appropriate administrative controls, if required, should limit the types of changes that can be made such that they do not require HFE input or review—the operator can simply select the desired configuration.

Three examples of modifications to operating plants that might be screened at different levels are:

- Level 1: An analog-to-digital conversion of the HSIs used to perform actions credited in the Final Safety Analysis Report (FSAR) for accident mitigation. Changing from conventional HSIs such as hard switches and meters to a computer-based HSI would represent a significant change to the HSI used for high-risk tasks.
- Level 2: A change to a TCS and associated HSIs. This system is very important to plant operation, and errors could have the potential to cause a plant trip or risk significant equipment damage and challenge the plant safety systems. A major modification or replacement of this system could result in an assignment of Level 1 HFE importance. However, the system to be used is well proven, having already been installed in several plants. Based on these considerations, the level is adjusted down to Level 2.
- Level 3: A modification that replaces the condensate polishing system controls. Although errors in working with this system could impact plant production, they would be slow to develop and likely would be discovered and corrected prior to becoming a problem with generation. The system does not have any significant nuclear safety risk or risk to plant personnel. On that basis, it is assigned to Level 3.

Because the Limerick SR I&C upgrade project impacts the I&C and HSIs of the Reactor Protection System and Engineered Safety Feature Actuation System functions credited in the facility FSAR, it is expected that the overall project modification would initially screen as Level 1. It is expected that individual tasks screening (and perhaps the project screen) may be tailored down as described above based on secondary factors.

Once a modification (or portion thereof) is assigned to a level, appropriate HFE activities can be identified. An example of tailored TA activities at the three levels is:

- For a Level 1 modification involving new tasks, a full TA is performed on those new tasks. This involves creating high-level descriptions of the tasks, and then decomposing them down to specific steps and activities to be performed. Detailed forms are filled in with this information. Task requirements are identified, HFE analyses (e.g., cognitive work analysis, Systems-Theoretic Process Analysis, timeline analysis, operational sequence analysis, etc.) as appropriate are prepared, and specific requirements for HSI support are identified. The results are documented in detail.

For a Level 1 modification to an existing task, the specific descriptions of the tasks should already exist. Those descriptions and associated breakdowns of the specific steps and activities to be performed to accomplish them should be evaluated. Depending upon the degree of impact to tasks and associated steps performed to accomplish them, it may be determined that the individual task screening (and perhaps the entire project screen) may be tailored down.

- For a Level 2 modification, the same TA forms as for a Level 1 modification can be used, but instead of filling them in in-detail, they can be used to make sure all the task steps are covered but in a more limited analysis of the task. For example, fewer scenarios might be used. Task and specific HSI requirements still need to be identified, but this step might be accomplished by a limited number of licensed operators walking through challenging scenarios in an operator training simulator or other realistic simulator representing the NPP being modernized. Observers including a HFE engineer should participate in the walkthrough, evaluate the results, and document the methodology used and task results.
- For a Level 3 modification, the analysis can be less formal. As with Level 2, walkthroughs can be used to describe the tasks, and results used to identify new or modified tasks. Existing procedures changed to reflect new or modified tasks could be created. It should be verified that task performance is adequately supported by the HSIs. The procedure itself becomes the documentation.

This tailored approach includes the concept of a "bounding HFE criteria." This means that for a certain domain of control room functions and tasks, similar operator tasks will be implemented in a consistent manner and therefore all future occurrences of these operator tasks are "bounded" by the analysis and implementation decisions of the first such occurrences. For example, one such domain could be the set of systems implemented in the plant distributed control system (DCS). While these systems would obviously have disparate functions, many of the operator tasks to monitor and control the systems would be highly similar. These would be such tasks as "control a plant parameter to a target value," "verify the expected values of a series of plant parameters," "monitor the time allowed (shot clock) to complete an action," and so forth. In other words, these basic operator tasks are repeated from system to system. Human factors principles would dictate that they be implemented in the same manner to present a consistent HSI to the operator.

On the other hand, there may be some operator tasks that would be unique and specific to the system under consideration. An example would be an operator task in the rod control system consisting of "pulling control rods to achieve a power change." Other operator tasks might be similar to some degree but have unique aspects that need to be analyzed on an individual basis. Such an example would be a unique control device that has one-of-a-kind operator inputs. These types of operator tasks would not be suitable to be included in the bounding HFE criteria.

The concept of a bounding HFE criteria would mean that once a particular task had been fully analyzed and designed, it need not be reanalyzed for usage within the same domain. This would be true for other similar instances in the plant functions that have been taken through the full HFE analysis process and similar instances in newly-considered plant functions. For example, the migration and enhancement of similar I&C functions from obsolete analog or digital systems to the digital platforms installed by the Limerick SR I&C upgrade project may identify new plant functions but some of the same operator tasks. These similar operator tasks would not need to have the analysis repeated in the same manner but could be simply implemented in a consistent manner as the first implementations on the new platforms.

As new operator tasks are fully analyzed and designed, they would then be added to the "population" of bounding HFE criteria such that any future instances are covered. In this way, the bounding HFE criteria is continually expanded and thereby able to reduce future HFE efforts proportionally.

In addition to bounding tasks, bounding is also applicable to other activities. For example, when certain features of the modification have already been verified and/or validated during previous modifications, credit can be taken for some of the previously performed verification activities. An example provided in an EPRI report [2] is a recorder replacement using the same model of the device as was utilized in another, already completed modification.

6.6.2 TASK ANALYSIS

TA is the analysis of functions that have been assigned to plant personnel in order to satisfy the requirements for successful performance. The actions personnel must do to accomplish functions assigned to them are called "tasks." Generally, the term "task" is used to refer to a group of activities that have a common purpose. The requirements developed in TA are a primary consideration in designing the HSIs, procedures, and training that are provided to plant personnel.

Objective. The objective of TA is to evaluate personnel tasks in sufficient detail to permit identification of the requirements for task performance (e.g., the alarms, information, controls, procedures, and training needed to perform the tasks). TA results have many uses in subsequent analyses, including staffing, error analysis, HSI and procedure design, training, and V&V.

Methodology. A generic methodology for performing TA is provided in an EPRI HFE guidelines report [2]. The major activities are shown in Figure 9.

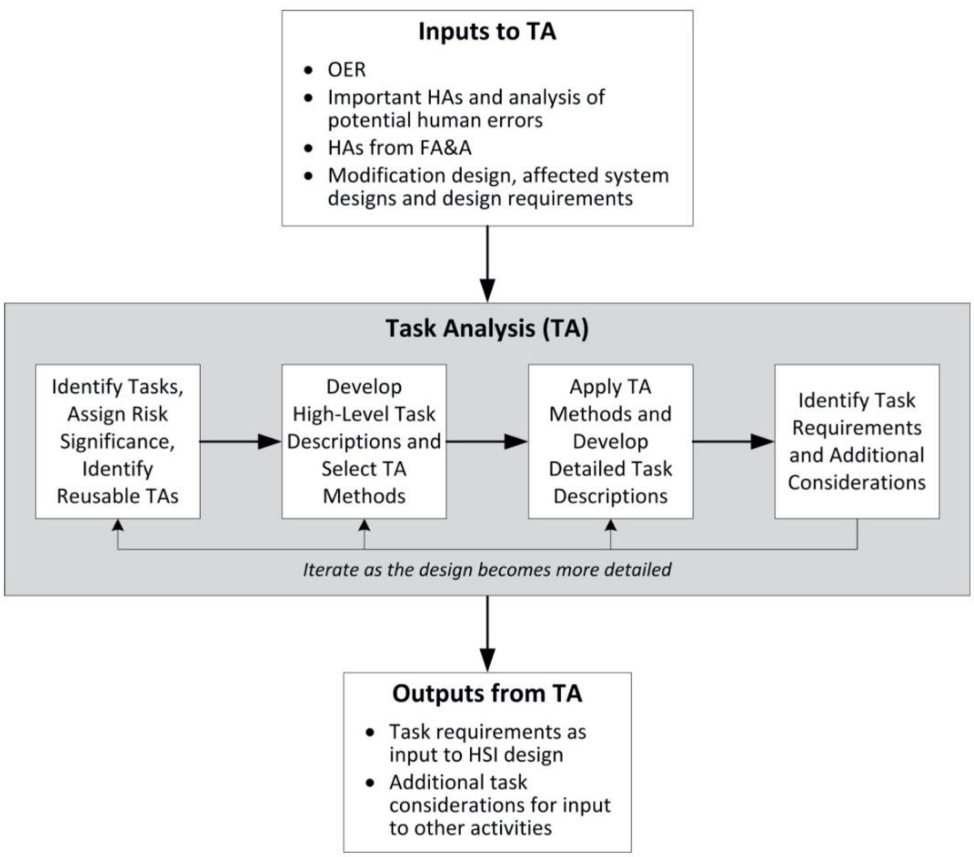


Figure 9. Overview of TA [2].

The methodology is divided into four major steps, as shown in Figure 9. The first is to Select Tasks to Analyze. The purpose of this step is to identify where detailed task information will be beneficial to the design. Once the tasks are selected, the next major step is to Develop High-Level Task Descriptions. Task descriptions provide information about the task, such as its purpose, its relationship to other tasks (e.g., performed in sequence or in parallel), the time it takes, etc. Using the high-level descriptions, Detailed Task Descriptions are developed by decomposing the tasks into detailed steps. The final step is to Identify Task Requirements. Task Requirements are the resources that must be available to perform the task (e.g., the information and controls required).

The steps above are described from a new design point of view. When performing a modification to an existing design, the same steps are applicable, but in many cases the documentation for existing tasks impacted by the modification is available. In such cases, this documentation, particularly for important human actions and tasks, is leveraged to determine how the modification impacts the performance of those actions.

Screening of tasks. The project level screening for the overall modification may have been assigned a Level 1 as described in Section 6.6.1 above because of the importance of the system. Once the individual tasks have been defined, however, it may become clear that not all of the tasks may be Level 1 in importance. Therefore, the candidate task list should be evaluated to determine the importance of the tasks using a tailored approach. Level 1 tasks should be analyzed in detail, whereas Level 2 and 3 tasks can be analyzed in less detail. The EPRI report [2] provides detailed guidance in Section 3.5.6 for screening tasks and defining appropriate levels.

The following aspects of tasks will be assessed as part of a tailored approach to determine the level of analysis to be performed for important and non-important human actions:

- Alerts and alarms
- Decision-making
- Response requirements
- Teamwork and communication
- Cognitive and physical workload and concurrent tasks
- Need for task support
- Workplace factors, such as ingress, egress, and other physical ergonomic factors
- Environmental or physical hazards that may affect operators.

There are several techniques that can be employed to perform a TA for a project such as the safety-related I&C upgrade at Limerick. The approach described below was used by INL in modernization efforts involving planning for the replacement of TCS and PPC systems at a subject utility. The TA was performed during a workshop performed in a training simulator located at one of the plants where the TCS and PPC modernization efforts were scheduled to take place.

TA workshop description. The TA Workshop was a follow-on to a FRA & FA workshop (described in Section 6.5), in which control room operators walked through scenarios relevant to interfacing with the existing instrumentation and controls, including computerized operator support displays like the Safety Parameter Display System (SPDS). A similar procedure was followed for the TA workshop.

The workshop was performed in an operator training simulator at the NPP where the modernization effort will take place. The simulation facility permitted control room operators to walk through the scenarios used during the FRA & FA workshop. The walkthroughs represented the conditions found in the control room doing operations. For example, the scenarios used a procedure reader since this is the practice at the NPP.

During the walkthrough, the simulator was stopped at steps in the procedure where tasks might be impacted by new or changed function allocations attributable to the modernization designs. The operators and others in attendance were asked to discuss these possible changes from existing practices. This process was followed for the remainder of the scenario and repeated for the remaining scenarios. As each scenario completes, the operators and observers review the scenario, identified functions, and the initial allocations made.

The walkthroughs followed a three-step process to observe and document information obtained during the scenarios:

- Observation of operator actions during scenarios

  This part of the process consisted of one or more analysts observing and recording operator activity. This method made use of computer-based forms that allowed the capture of start and end times of significant actions or events during the first scenario trials. Specific attention was paid to actions or functions that could be improved or simplified by allocating to automation or by providing task support.

  This method minimized the intrusion operators may otherwise experience from too frequent interrogation by the analyst. A typical shortcoming of this method was the difficulty in recording sufficient detail of the activity. This was mitigated through the other three methods, which helped to produce a detailed analysis.

  Some scenarios received multiple walkthroughs, the first in order to allow the operators to proceed through the event naturally without interruption by the observers, and a second time in a think-aloud method in which the operators explained their decisions and actions, frequently with intentional simulator runtime pauses to allow questions by the observers.

- Debrief and summary discussions

  This consisted of a group review of the scenarios, and the primary focus was on those actions or events that could indicate opportunities for improved task and HSI design, due to workload, error probability, or some other inefficiency.

- Identification of operator performance requirements

  This part of the analysis was conducted as part of the debriefing sessions and focused on identifying cognitive and physical performance requirements for the task. The analyst used prepared forms to record additional information that also helped participants understand how task performance is influenced by the procedures and by the current design of the system and control boards.

  The following dimensions of performance were analyzed:

- Information requirements (alarms, alerts, values, instructions)
- Decision-making requirements (decision type, evaluation type)
- Response requirements (frequency, error tolerance, concurrent tasks, accuracy, consequences of incorrect or non-performance, time constraints)
- Communication requirements (written, verbal)
- Workload factors (visual, auditory, cognitive, physical)
- Task support requirements (procedures, job aids).

  Constellation intends to follow a similar approach for the Limerick safety-related I&C upgrade.

Results. A technical report will capture the output of this planning and analysis HFE activity. It will document the TA results for use by the HFE team and other engineering groups involved in the modernization effort. The task requirements identified will be applied to activities associated with subsequent elements in the design process (e.g., HSI design and HFE V&V).

It is expected that the continued TA related efforts will occur during the iterative HSI design process as described in Section 6.12.1, including HSI static and dynamic workshops. As HSIs are reviewed, evaluated, and refined during subsequent HFE Task Support Verification, ISV, and Design Verification activities, issues that are identified that could negatively impact the operator's ability to perform necessary tasks will be reviewed and dispositioned.

6.7 Staffing and Qualification Analysis

Objective. Identify potential staffing and qualification impacts introduced for the Limerick SR I&C upgrade project.

Methodology. The staffing and qualifications element analyzes the requirements for the number and qualifications of personnel in a systematic manner. This includes an understanding of task requirements and applicable regulatory requirements. This element is coordinated with Section 13.1 of the FSAR, which also relates to organization and staffing. The staffing analysis is iterative in nature and discusses how the initial staffing goals have been reviewed and modified as the analyses associated with other HFE elements are complete.

Staffing and qualifications need to be consistent with the demands of the assigned tasks. TA for the upgrade provides important input, defining the knowledge, skills, and abilities required to perform tasks assigned to staff members. These requirements are used to determine staffing qualification criteria and support the design of procedures and training material.

Results. A report capturing the output of this activity. It is not expected that the Limerick SR I&C upgrade will fundamentally impact the staffing and qualification requirements for plant personnel. It is expected that plant procedures will be impacted and that personnel will need to be trained on the characteristics of the new system's functions and capabilities. Impacts to procedures and training are addressed in Sections 6.13 and 6.14, respectively.

6.8 Important Human Actions

The treatment of Important HA elements is concerned with HAs that are most important to safety. These analyses identify the risk-important HAs described in Chapter 19 of the FSAR as an integral activity of a complete Probabilistic Risk Assessment. Deterministic engineering analyses generally are completed as part of the suite of analyses in the FSAR per the NUREG-0800 Standard Review Plan, Chapter 7, Instrumentation and Controls, and Chapter 15, Transient and Accident Analyses. These analyses sometimes include credit for HAs by operators as part of an evaluation.

Objective. Human reliability analysis (HRA) seeks to evaluate the potential for, probability of, and mechanisms of human error that may affect plant safety. Thus, it is an essential element in achieving the HFE design goal of providing a design that will minimize personnel errors, allow their detection, and provide recovery capability. HRA can provide valuable insights by identifying undesirable design characteristics and the causes, modes, and probabilities of human error.

Methodology. HRA identifies important HAs enveloped within the Limerick SR I&C upgrade project scope. Existing important HAs for the legacy systems being impacted by the upgrade will be identified by Constellation. Any new important HAs will be identified by a screening analysis as described in NUREG-1764 [6]. The identification of important HAs will also be considered in a manner consistent with guidance in NUREG-0711, where applicable. HRA then makes use of the outputs of function and TAs, specifications of HSI characteristics, and other inputs to identify if the legacy important HAs are impacted by the upgrade and whether new ones are generated. Manual actions identified during a defense-in-depth (D3) analysis that are credited to cope with a PPS common-cause failure will also be addressed as part of this effort. These are then assessed by the PRA and HFE teams. A tailored, risk-informed approach per NUREG-1764 [6] is then used to determine the appropriate level of HFE review. PRAs and HRAs assessments are performed early, iterated, and finalized when upgrade design and HFE activities are completed. The study and analysis results are used by the HFE modernization team to identify issues requiring consideration in the HSI design. Important HAs will be evaluated using the acceptance criteria provided in NUREG-0800, Chapter 18 [5], Attachment A, "Guidance for Evaluating Credited Manual Operator Actions." Additional guidance from EPRI 3002004310 [2] on the treatment of important human actions will be reviewed for applicability and used, if appropriate.

An analysis of the how this upgrade may affect the availability and reliability of necessary HSIs and impact manual actions to achieve and maintain hot shutdown conditions during and after a fire event as presented in NUREG-1852 [19] will also be performed as part of this activity. More broadly, the guidelines presented in its Appendix A on using timelines to investigate and illustrate that sufficient time exists to perform the post-fire operator manual actions will be used, when appropriate, to analyze time-critical aspects of any important human actions that are determined to need this additional analysis (i.e., to illustrate that there is adequate time available to perform all relevant actions and account for additional uncertainties that might not be covered by the demonstration of the action).

Results. A report capturing the output of this activity. It will document how any changed or newly created Risk-Important Human Action is being addressed by subsequent elements in the design process (e.g., HSI design and HFE V&V).

6.9 Verification and Validation: Simulator Strategy

Per NUREG-0711 [1] Section 11.1, ISV is an evaluation, using performance-based tests, to determine whether an integrated system's design (i.e., hardware, software, and personnel elements) meets performance requirements and supports the plant's safe operation. In order to execute an ISV for the Limerick SR I&C Upgrade, a facility needs to exist that is capable of supporting these performance-based tests.

Section 11.4.3 of NUREG-0711 states that he scenarios for ISV should be performed using a simulator, or other suitable representation of the system, to determine the complete design's adequacy to support safe operations. Validation should be performed after the resolution of all significant human Engineering Discrepancies (HEDs) identified in verification reviews. Constellation will provide an MCR simulator of sufficient fidelity to perform ISV for the upgrade. Development activities to ready this simulator for performance of ISV (physical modifications driven by the design of new or modified HSIs, loading of HSI and control system software, and necessary simulator infrastructure modifications to enable this software to support ISV performance) are incorporated within the project schedule for the upgrade.

6.10 Human-System Interface Style Guide

A design-specific HSI Style Guide will be developed for the Limerick SR I&C upgrade project. This style guide will provide specific guidance to design new and modified HSIs included as part of this effort while at the same time promoting consistency in the design of HSIs across the MCR panels to the extent possible. The style guide will address (a) organization and presentation of information on individual display pages to be presented on physical video display units (VDUs), (b) organization and navigation between display pages, (c) design of display fonts and symbols and use of color coding and labeling, and (d) design of touch panels to provide for operator input of decisions if this type of HSI is desired. The style guide will also provide instructions for its use in the overall design process.

This style will be informed by generic guidance provided by NUREG-0700 [11]. It will also be informed by HSI-related information from the selected vendor, including:

- Human Factors Engineering Guideline for the Common Q Display System (WNA-IG-00871-GEN, Rev. 0) [18]
- Global Instrumentation & Controls Control & Information Systems Engineering Human-System Interface Display Implementation Guidelines (WNA-DS-04213-GEN, Rev. 1) [17]
- AP1000 Interface Specification for Class 1E DC Motor Operated Valves (APP-GW-J4-003) [13]
- AP1000 Protection and Safety Monitoring System - Technical Manual (APP-PMS-J0M-003, Rev. 2) [14]
- AP1000 Human-System Interface Design Guidelines (APP-OCS-J1-002) [26].

The HSI Style Guide will also consider information related to other HSIs resident in the MCR, such as:

- Human Factor Engineering Detailed Design Review In-Process Audit [15]
- Limerick Generating Station Unit 1 & 2 Turbine Control System Upgrade Display Design Functional Requirements & Implementation Guidelines (WNA-DS-02820-GLIM, Rev. 1) [16].

Constellation has already selected an I&C vendor and the vendor platforms that will be used to accomplish the Limerick SR I&C upgrade. The selected platforms were used in the Westinghouse AP1000® for safety-related and non-safety related I&C applications including HSIs in the AP1000 MCR. The intent is to leverage the native capabilities of these platforms as much as practicable while addressing specific issues when applying them to Limerick. This not only supports better HSIs that support improved operator performance, but also supports a simplified HSI implementation, reduces associated implementation costs, and enables more efficient lifecycle management.

6.11 Conceptual Design Human-System Interface Display and Navigation Strategy

Objective. While not a specific activity called out in NUREG-0711, developing an HSI Display and Navigation Strategy early in the design process provides an opportunity to engage Constellation operations personnel and familiarize them with the capabilities of new technologies in general and the selected vendor I&C platform in particular. Experience in addressing HFE in previous I&C and MCR upgrades has identified that, by educating Operations personnel early on these capabilities and soliciting their input, they become much more engaged earlier in the upgrade process and drive HSI and control system functionality for the project. Identified functionality is then provided as an HSI design input.

Methodology. Prototype HSIs depicting operational and HSI concepts will be presented to Limerick operations, engineering, and simulator training personnel as part of the TA workshop described in Section 6.6.2. These prototypes will be developed based upon Limerick operations input. I&C Vendor involvement also is critical to ensure results are implementable. This effort is intended to specifically support further HSI design. It is also intended to facilitate operations input and support to refine the overall Concept of Operations (Section 6.3) and shape the MCR "New State" Vision (Section 6.2).

Results. The report which documents the planning and analysis phase TA efforts will capture the conceptual HSI display and navigation strategy as an input to Limerick SR I&C upgrade design.

6.12 Vendor Human-System Interface Design, Oversight, and Human Factors Engineering Issues Tracking

As described in NUREG-0711, Rev. 3, "The HSI design process represents the translation of function and task requirements into HSI characteristics and functions." For this upgrade, many fixed, analog HSIs are being migrated to graphical displays. Manual controls and indications are also expected to be impacted.

As depicted in Table 4, the elements of the Planning and Analysis phases each provide key information used in the vendor design of the new HSI for the control room.

Table 4. Use of HFE program elements in HSI design.

HFE Program Element	Use in the HSI Design
OER	Lessons learned on previous system use and identification of important human actions
FRA & FA	Opportunities for automation of displays and system execution; required role of operators in controlling the system
TA	Information and tools required by operators to support task execution
HSI Style Guide	Requirements for controls, navigation, visual presentation, and other HSI elements

Other items that must be considered include:

- Constraints imposed by the modernization hardware and software
- Existing HSI designs at an NPP where the modernization effort was performed
- Applicable regulatory requirements.

This information is combined with a specification for each HSI display created for or each physical panel modification made by the Limerick SR I&C upgrade. The specifications may be developed according to the sections below.

6.12.1 HUMAN-SYSTEM INTERFACE DESIGN

6.12.1.1 GRAPHICS DISPLAYS

Each HSI display specification developed by Constellation should include a general name of the display (corresponding to plant naming and numbering conventions), a description of the function of the display, a description of the placement of the display. (e.g., some displays may be statically located (e.g. a dedicated PPC VDU, while others may be pulled up from any DCS VDU (e.g., a RRCS function display)), assumptions regarding the hardware (e.g., size and resolution VDUs), information about the control mechanism (e.g., soft controls using a touchscreen vs. mouse or keypad control), and version information. Additionally, the specification should address the required information found in Figure 10, namely the relationship between operator/system inputs, the program logic, and the operator/system outputs.

Figure 10. Required information for display specification.

The system inputs (e.g., temperature at a certain sensor point) and outputs (e.g., valve close signal) may not be displayed to the operator in all cases, but their background use should be clearly documented in the specification.

The specification should also feature documentation about any design considerations from the Planning and Analysis phase that influenced the design. For instance, the FRA and FA (Section 6.5) and

TAs (Section 6.6.2 report(s) for the Limerick SR I&C upgrade project are expected to identify new functionality that would be advantageous to the operators. An example iterative approach tailored for HSI display design can be found below in Figure 11.

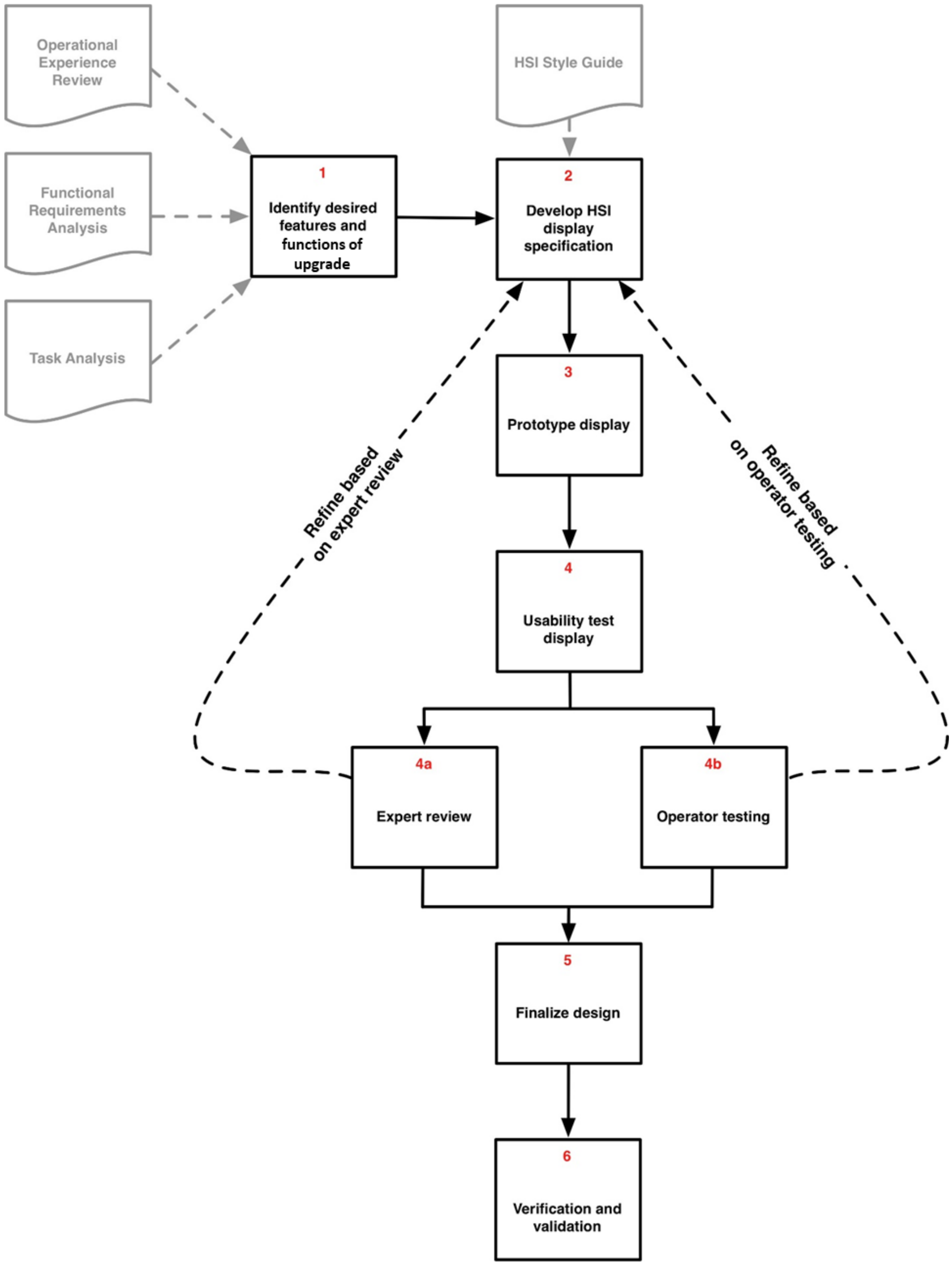


Figure 11. Flow diagram for developing new HSI displays.

The approach has five basic steps:

1. Identify the desired features and functions of the HSI display—whereby insights are extracted from the Operational Experience Review (to the extent there may be deficits in the existing HSI), the Functional Requirements Analysis and Function Allocation, and the TA. There should be a clearly documented need for the new functionality as demonstrated by an existing performance deficit (e.g., as a cumbersome or error-inducing HSI) or the opportunity for operator performance improvement (e.g., increased reliability through automation or improved operator response time). While operator desires for new features may be considered, the basis for new features and functions should remain grounded in opportunities for improved reliability, safety, and performance.
2. The desired features and functions are turned into a specification by Constellation. This display specification should conform to the HSI Style Guide (Section 6.10).
3. The specification is prototyped to a degree suitable for evaluation. The prototype can be as simple as a line sketch of the interface or involve using the DCS graphics development tools to create an early version of the final implemented DCS. The prototype should contain sufficient fidelity such that dimensions and colors can be depicted accurately. If the native DCS environment is used in the prototype, it is not necessary to enable all functionality. The prototype will be evaluated, and it is important that the prototyping phase not be considered the end development and deployment stage. The prototype may be discarded in favor of better designs, once the usability testing is complete.
4. The prototype is usability tested. Usability testing is the process of assessing the degree to which the designed system can be used effectively by the target user. Success metrics range from user satisfaction to user performance. In the case of the usability evaluation of the DCS displays, the goal is foremost to ensure that operators understand and can operate the HSI elements, from navigating between different displays in the DCS to controlling parts of the plant using the DCS. The usability evaluation is ideally formative, meaning it is used not only to verify the usability of the designed system but also to help specify the design in an iterative fashion. There are two accepted ways of usability testing:

    A. Expert review—in which subject matter experts in human factors, nuclear operations, or control systems review the HSI. This review may follow specific usability criteria called heuristics or provide an overall impression of how the HSI would be used and any deficiencies they might note. Expert reviews are especially useful early in the design phase when a full-scale V&V will be conducted later in the development cycle. INL will participate in this expert review.

    B. Operator testing—which can range from walkthroughs with nonfunctional mockups to scenario testing using fully functional prototypes. The level of fidelity and functionality is a product of the resources of the design team and the degree to which the new functionality diverges from current plant operations. Note that operator testing at this stage will typically focus on the DCS HSI alone and not in the overall context of the control room. ISV—testing of the new DCS in the full control room—occurs at the V&V phase.

    Results from the usability testing phase should be used to refine the design. If there are design deficiencies, the design should be revised and the process iterated starting at Step 2. INL will participate in the evaluation of operator testing results.

    In addition to tabletop reviews by the HFE Team, HSI design static and dynamic workshops are planned to facilitate focused prototype display usability testing. This is a continuation of the TA activity into the design phase. During these workshops, new and/or impacted important human actions associated with this upgrade will specifically be evaluated following the preliminary validation process as outlined Attachment A, "Guidance for evaluating Credited Manual Operator Actions" to NUREG-0800, Revision 3 (2016), Chapter 18, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition – Human Factors Engineering" [27].

It is expected that as part of this effort, operational sequence diagrams or similar will be employed. This method consists of identifying the key human and system "actors" in scenarios, the interactions between them, and the information (signals) produced by systems being accessed by operators. The sequential actions are plotted on a timeline to help decompose functions into tasks, subtasks, and task elements.

This method provides a framework that helps analysts investigate the nature of human interaction with the system, their timely execution of human actions, as well as opportunities for improvement.

As the HSI design converges, Task Support Verification activities will be performed on those HSIs (See Section 6.16.1 below) using procedures that have been modified to reflect the upgrades. It is not anticipated that new HSI graphics functionality incorporated into the control room by itself would require a change in plant operating procedures. Functional changes, such as the implementation of new control features (including automation), will require procedure changes. HSI and procedure issues identified during Task Support Verification are then dispositioned.

5. Constellation and their I&C vendor leverage the output of Items 1–4 directly above to finalize the HSI design. Once the HSI prototypes have been evaluated and it has been determined that the HSI can be used successfully and safely by operators in the control room, these HSIs will be rendered by the vendor in the appropriate platform (PPS and DCS) design tools. The associated design specifications, which include these renderings, are finalized. Procedure changes identified through this process are also finalized.

6. The finalized HSI display design will be used to complete the V&V phase, which is documented in Section 6.16.

HSI displays should be developed in accordance with a standard user-centered design method, such as ISO 9241-210 (2019), Ergonomics of Human-System Interaction – Part 210: Human Centered Design for Interactive Systems [24], and ISO 9241-10 (1996), Ergonomic Requirements for Office Work with Visual Display Terminals (VDTs) – Part 10: Dialogue Principles [25].

6.12.1.2 SPECIFICATIONS FOR PLACEMENT AND FUNCTIONALITY OF CONTROL SWITCHES AND DIRECT INDICATIONS

Following the Three-Mile Island plant accident, the U.S. NRC and industry established requirements for improved accident monitoring and control. Several systems have been implemented in the existing design in response to these requirements, including SPDS, Post-Accident Monitoring System (PAMS), and Bypassed and Inoperable Status Indication (BISI) [2]. These safety-related systems each have specific purposes and requirements and may not follow the conventions seen across other HSIs in the plant. When modernizing safety-related control and indication, there is the opportunity to ensure consistency with existing conventions with close consideration of their requirements while adapting SPDS, PAMS, and BISI to allow them to reside digital systems with VDU-based HMIs.

Fundamentally, the core functions of the SPDS and PAMS are not being modified by the upgrade. The SPDS-PAMS display function will be accomplished by collecting SPDS-PAMS inputs using the four PPS channels. These indications can be shared for presentation purposes between the four PPS channels so that it is possible to view all SPDS-PAMS parameters for any one PPS VDU. This information will also be passed to the non-safety DCS so that SPDS-PAMS parameters can also be viewed from VDUs on that system.

With regard to the BISI functions the upgrade digitizes, and in many cases changes, the voting logic for existing safety system functions (for RPS, ECCS, and N4S) that are being migrated to the new PPS. For example, the one-out-of-two taken twice logic for PPS is being replaced by a four-channel, four-division PPS, which provides separate voters. The modified voting scheme and associated BISI indications will be presented on PPS displays on each of the four divisionalized VDUs. Since information associated with indications on one PPS division can be shared for presentation with the other three divisions, each PPS division VDU can present BISI information from all four channels and divisions. Actual bypassing of individual channel inputs and individual division voting logic within PPS can only be performed from one paired channel/division (e.g., Channel 1/Division 1).

To ensure a diverse PAMS backup exists in the case of a PPS common-cause failure, all necessary PAMS variables, as well as RRCS functionality, will be separately available on the DCS segment that provides diverse functionality.

As HSI's are developed during the design phase, the method of presenting the above PPS and DCS capabilities for providing SPDS, PAMS, and BISI on VDUs will be established. This may require addressing how these parameters are presented where display presentation on VDUs is dynamic and VDU real estate is limited. Such design attributes may drive consideration of converting "continuously-viewable" SPDS, PAMS, and BISI indications to being "continuously-available" through simple display page navigation.

Many manual control switches from the current design are to be removed by the upgrade. Control actions governed by the switches that are removed will be migrated to display pages developed as described in Section 6.12.1.1. The location, accessibility, capability, and use switches that remain or that may be added by the project will also be evaluated such that they support harmonious operation with the rest of the Limerick SR I&C upgrade and the overall MCR concept of operations. This will also be coordinated with display page development, as described in Section 6.12.1.1.

6.12.2 DESIGN OVERSIGHT

Design oversight of the vendor for the Limerick SR I&C upgrade project is the responsibility of Constellation and will be performed in accordance with Constellation's vendor oversight plan and applicable licensee procedures. The Project Manager and Responsible Engineer are responsible to ensure that the HFE Design Team's recommendations are properly addressed and dispositioned as part of the Engineering Change process at the Limerick Generation Station.

6.12.3 HUMAN FACTORS ENGINEERING ISSUES TRACKING

HFE issues shall be tracked within a HFE Issues Tracking System (HFITS), which provides a means to record and track issues throughout the design, development, and evaluation process. HFE team tracking ends when the design implementation activity is completed and all issues are closed.

The HFITS will:

- Identify problems, issues, and discrepancies and enter them into the log with a unique tracking number
- Assign administrative responsibility for maintaining the tracking system and tracking logs
- Evaluate and document proposed resolutions and the residual effects of the implemented resolutions for the issue
- Identify responsibilities for HFE team members regarding issue identification, resolution, and closeout.

NUREG-0711 [1] suggests that individual HFE issues be identified and tracked. These should either be corrected for acceptable control room functionality or be deemed acceptable as is. HFE issue tracking is a Constellation and vendor responsibility. To accomplish this end, an expanded classification and associated priority levels will be used as described below:

- **Priority 1:** Have direct, indirect, or potential safety or plant availability consequences and require resolution prior to modification being placed in-service.
- **Priority 2:** Potential consequences to plant performance operability or personal performance and formal disposition (resolution prior to the modification being placed in-service, deferred resolution at next available opportunity, or accept as is) shall be documented.
- **Priority 3:** Other (not meeting Priority 1 or Priority 2 criteria).

6.13 Evaluation of Impacts to Procedures

Procedures are essential to plant safety because they support and guide personnel interactions with plant systems and personnel responses to plant-related events. Constellation is responsible for procedure changes made necessary for the Limerick SR I&C upgrade project in accordance with their procedures program.

Procedure changes will be supported by analyses used to develop the HSIs and training program for this upgrade. All three of these elements will be subject to the common evaluation process to ensure that they work together to maximize operator performance. For example, as the HSI design is converging as described in Section 6.12.1.1, the design verification of the displays will occur using procedures that leverage them. Any procedure changes driven by changes in I&C functionality will be examined during the HSI design verification to ensure that the procedures and HSI displays are compatible. The same HFE principles will be applied to procedures and HSIs provided to personnel as impacted by this upgrade.

The procedure modifications will address all personnel tasks affected by the changes in the plant systems and HSIs. The procedure will be developed or modified to reflect the characteristics and functions of the modifications made as part of this project.

Procedure changes will be developed in a way that addresses the review criteria in Section 9.4 of NUREG-0711 [1].

6.14 Evaluation of Impacts to Training

Limerick plant personnel training is important in ensuring they can safely and reliably operate the plant after the SR I&C upgrade project is completed. The Constellation training program aids in offering reasonable assurance that Limerick personnel have the knowledge, skills, and abilities to perform their roles and responsibilities. Training associated with this upgrade will be based upon an analysis of job and task requirements impacted by the upgrade, as identified in the TA (Section 6.6.2), subsequent static and dynamic workshops, and ISV lessons learned. Training program changes will address all personnel tasks affected by the changes in plant systems and HSIs.

Objectives of this project-specific training effort include:

- Systematically analyzing tasks and jobs to be undertaken
- Developing learning objectives derived from analyzing the desired performance after training
- Designing and establishing training based on the learning objectives
- Evaluating the trainees' mastery of the objectives during training
- Assessing and revising the training based on the performance of trained personnel in the job setting.

Constellation training-related activities for this upgrade will address the review criteria of Section 10.4 of NUREG-0711 [1] by following their operational training program. This will be integrated by Constellation into this HFE overall program.

6.15 Verification and Validation: Detailed Integrated System Validation Execution Plan

ISV has two components:

- Determine if the integrated design meets performance requirements
  - Minor change—may be user walkthrough
  - Major change—may be in training or similar simulator
  - Tests involve personnel who will use HSIs
  - Challenging and representative scenarios selected
  - Plant and personnel performance measures selected.
- Validate
  - The role of plant personnel, staffing, and task assignments
  - Adequate alerting, information and control are provided
  - Procedure changes have been developed permitting the proper use of the upgraded HSI and control system features
  - Operators provided with sufficient training can operate the upgraded systems and HSIs and meet performance requirements.

HFE issue resolution objectives include (1) evaluating the issue to determine if it requires correction, (2) identifying design solutions to address the HFE issue that must be corrected, and (3) verifying the completed implementation of necessary HFE issue resolution design solutions.

Performing the ISV on the Limerick SR I&C upgrade will be a significant effort due to its scope and complexity. Consequently, a separate, detailed ISV plan will be developed to ensure that all aspects of the project necessary to accomplish it are properly coordinated. The design and deployment of the HSIs as well as other necessary efforts (procedure development, training, etc.) will require a variety of plant and outside personnel. The legend provided in Table 5 identifies the primary stakeholders required to carry out the plan. Primary stakeholder roles not defined in Section 6.1 are included in Table 5.

Table 5. Participants in Limerick Safety-Related I&C upgrade project.

Plant Personnel	Non-Plant Personnel/Subcontractors
SE Systems engineers Engineers assigned responsibility for legacy systems impacted by the SR I&C Upgrade **IC** I&C engineers **PO** Plant operators **CS** Computer system engineer (simulator) Individuals who maintain/support the computer systems that enable plant simulators **PT** Personnel training and simulator operations Individuals who train operators in a classroom	**V** I&C HSI vendor **HF** Human factors engineers (e.g., INL) **AE** Architect engineers Engineers from a firm (e.g., Sargent & Lundy) who provide support services such as creating installation drawings, performing calculations, etc.

Plant Personnel	Non-Plant Personnel/Subcontractors
environment and those who operate the plant simulator for training **PW** Procedure writers Individuals who author operating procedures	

Table 6 provides a notional execution timeline of design implementation and related HFE activities that culminate in performance of an ISV, disposition of identified HFE issues, and deployment of the final HSIs in both the training simulator and the Limerick MCR.

Table 6. Notional HSI design, simulator integration, and ISV schedule.

			Time Period												
Task	Activity	HFE Plan Section	1	2	3	4	5	6	7	8	9	10	11	12	Personnel
1.	Physical Switch and Direct Indication Design Specification	6.12.1.2	■	■											SE, IC, V, HF
2.	Physical Switch and Direct Indication Migration Design			■	■	■									PO, V, HF
3.	Physical Switch and Direct Indication Simulator Implementation	6.16.2				■	■								V, SE, IC, AE, CS
4.	Display Design Specification	6.12.1.1	■	■											SE, IE, V, HF
5.	Display Design			■	■	■									PO, V, HF
6.	Display Simulator Implementation	6.16.2				■	■								V, SE, IC, AE, CS
7.	HSI Usability Test in Simulator	6.16.2					■	■							PO, V, HF
8.	ISV Scenarios Selected and Validated	6.13, 6.14, 6.15						■	■						PT, PW, HF
9.	ISV Execution Plan (develop and prepare to execute)								■	■					HF, PO, PT, PW
10.	Perform HSI ISV and Document Results	6.16.2									■				HF, PO, PT
11.	Resolve HSI Issues											■			SE, IC, AE, CS, V
12.	All New HSI Deployed in Training Simulator	6.14										■	■		V, SE, IC, AE, CS
13.	Operators Trained on All New HSIs in Training Simulator												■	■	PO, PT, PW
14.	All New HSIs Deployed in Main Control Room	6.17												■	SE, IC, AE, V

Table 6 Tasks 3 and 6–13 require that a simulator be available that is capable of supporting the incorporation of the new HSIs (in Time Period 4) and running through ISV and operator training activities (Period 12).

While Table 6 shows a linear process, the actual execution will be iterative. For example, initial simulator implementation of displays and physical devices (meters and switches) can be used by design, operations, and training organizations to become familiar with the new design (training), support early design evaluation, and promote procedure development. After ISV, the simulator can be used to ensure any design modifications made as a result of HFE issues identified by ISV are properly dispositioned (through HSI design changes, procedure changes, or training).

The scenarios developed by the HFE Design Team in collaboration with plant operations and training and simulator operations are designed to test the SR I&C upgrade project developed HSIs as an integrated set under complex and challenging conditions. ISV is performed in a plant simulator to ensure that the HSIs work as intended both within the scope of the project and also in concert with related MCR controls and indication to affect satisfactory overall plant control. The ISV scenario set is intended to complement (not duplicate) the task support and design verification activities described in Section 6.16.1.

6.16 Human Factors Verification and Validation

Objective. HFE V&V are to establish that the HSI design meets design requirements and to ensure that the interface is effective in supporting the performance of personnel tasks. To demonstrate this, it must be established that the HSI meets all of the requirements that have been placed on it and that it will enable all the intended tasks to be carried out effectively.

It is determined during the HFE V&V element whether the modernized design:

- Provides all necessary displays, controls, alarms, and procedures to support plant personnel tasks
- Conforms to HFE design principles, guidelines, and standards
- Can be effectively operated by personnel within all performance requirements
- Has resolved all identified HFE issues.

An overview of V&V activities is shown in Figure 12 [4].

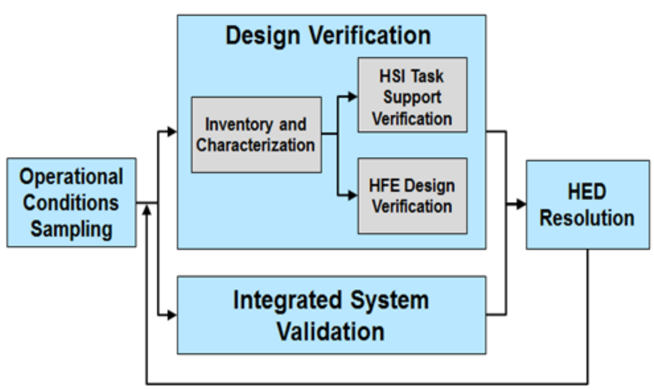


Figure 12. Overview of V&V activities.

Operational conditions sampling will be required since the modification involves many HSI changes and will be used in a wide range of operational conditions. Examples of sampling considerations include the:

- Range of normal and abnormal plant conditions
- I&C and HSI failures and degraded conditions

- Transients and accidents
- Human actions and tasks identified as risk significant in the HRA or OER
- Cognitive tasks not well-defined by procedures
- Situational factors (e.g., high workload, environment).

Methodology. The methodology for design verification and ISV activities are presented in the corresponding subsections below.

6.16.1 HUMAN-SYSTEM INTERFACE TASK SUPPORT AND DESIGN VERIFICATION

HSI task support verification ensures that new or modified HSIs address personnel task requirements determined by task analyses by:

- Providing all alarms, information, control and procedure capabilities required
- Identifying and dispositioning HFE issues associated with implementation of TA results identified during the HSI design and/or during procedure development.

Task support verification is captured in the project schedule such that it is completed prior to ISV. Any HSI or procedure issues identified prior to ISV will be dispositioned prior to the performance of ISV.

HFE design verification issues include the following.

- Verify modernized HSIs designed to accommodate human capabilities and limitations by applying criteria in the Style Guide and NUREG-0700 [11] or EPRI 300200319 [2].
- Any HSI design feature not verified as acceptable is designated as an HFE issue that is tracked, evaluated, and properly dispositioned using the HFITS.

As depicted in Figure 12, design verification can occur in parallel with and iteratively with ISV. Based upon the project-integrated master schedule, many, but not all HSIs used for ISV will have completed design verification prior to ISV. Provisions have been made in the project-integrated master schedule to ensure there is an opportunity to disposition any HSI design issues identified during ISV or as part of the parallel design validation process. There will be an opportunity to perform design and HSI regression testing on any HSI modifications implemented as part of these parallel processes if needed.

Results. This is accomplished by:

- Ensuring that HSI attributes identified to satisfy task requirements as documented in the TA technical report (Section 6.6.2) and report(s) capturing additional TA related results from the HSI static and dynamic workshops (Section 6.12.1.1),
- Ensuring the HSI Style Guide (Section 6.10) attributes have been incorporated into the appropriate HSI specifications and that the resultant HSIs satisfy those specifications. Procedure reviews ensure that their use, when executing tasks via the provided HSIs, accomplishes the intended results.

Design verification reviews are performed and documented by Constellation as part of the Vendor Oversight process.

6.16.2 INTEGRATED SYSTEM VALIDATION: PERFORM AND PRODUCE REPORT

ISV will be executed in accordance with the detailed execution plan developed in accordance with Section 6.15.

Preparatory steps will be taken to ensure that all necessary arrangements have been made to enable the successful ISV execution. This will include (but are not limited to):

- Identifying the operators who will be the subjects who participate in the ISV
- Ensuring operator subjects receive sufficient familiarization training on both the attributes of the design change and the revised procedures prior to its execution
- Verifying that the new HSIs developed for this upgrade, along with associated control emulations associated with the new I&C design, have been fully incorporated into the simulator
- Conducting a preparatory workshop where an ISV dry run will be performed with operations personnel who will not be ISV operator subjects, which is an invaluable step to ensure:
    - Scenarios have been properly selected
    - The simulator is capable of supporting ISV by running those scenarios
    - Simulator training personnel are able to properly run the simulator to execute the scenarios
    - Potential simulation limits that may be encountered during ISV are identified and methods to deal with them are identified in advance
    - An evaluation of any open HFE issues that may impact ISV execution
    - Necessary procedures are available not just to address the evaluation of the direct scope of the Limerick SR I&C upgrade project but for all systems in the MCR
    - That overall workload in the MCR is properly simulated (e.g., routine communications, work package processing, minor plant issues not directly related to the scenarios)
    - An examination of the use of "time compression" of extended, "low intensity" activities (e.g., a reactor startup) during scenario execution to maximize the access to operator expertise for performing the ISV while accounting for the limited availability of operator subjects
    - If the familiarization training provided to operator subjects on the new design and associated procedure changes properly covers the envelope of activities that will be performed during ISV
    - That sufficient HFE subject matter expert observers have been identified along with their roles and necessary tools (observation forms, recording devices, etc.) to ensure that necessary data is captured during the ISV
    - That structured ISV scenario and overall "out-briefs" have been preplanned with necessary tools for data capture. The overall ISV out-brief should include not only the operator subjects and HFE subject matter experts but also simulator training personnel, Responsible Engineer, Project Manager, and appropriate Limerick Station management personnel
    - The creation of the final ISV execution plan/schedule based upon information gathered during the workshop.

Any HFE issues identified during ISV, along with those identified prior to ISV, will be captured as HEDs. These will be prioritized using the same methodology identified for HFE issues in Section 6.12.3 (Priority 1, 2, and 3). Recommendations for their disposition will also be provided.

A representative outline of the final ISV report to be produced is:

- Introduction
- Validation Team and Independence

- Validation Approach
  - Validation Objectives
  - Performance Criteria
  - Project and Plant Basis for Scenario Items
  - Test Design and Test Procedure
  - Performance Dimensions and Measures
  - Selected Performance Measures and Observations
  - Method for Identification and Analysis of HEDs.
- Results
  - Performance Measures
  - HED Identification, Analysis, and Prioritization.
- Validation Conclusion.

6.17 Human Performance Monitoring

Constellation's human performance monitoring program will provide reasonable assurance that the confidence developed by completing a thorough HFE Program, culminating with the V&V of the control room and integrated systems design described in Section 6.16.2, is maintained over time.

HEDs from the ISV that are dispositioned for future tracking as identified in the ISV report produced as described in Section 6.16.2 will be managed by Constellation. It is expected that these will be managed along with any additional HEDs that may be identified after the Limerick SR I&C upgrade project is closed out in the site CAP.

This is consistent with the guidance provided in Section 13 of NUREG-0711 [1], which states that a utility may incorporate this monitoring program into their problem identification and resolution program and their training program.

7. SECOND UNIT DELTA ANALYSIS

The Limerick SR I&C upgrade will be performed on two units, with Unit 1 implementation preceding Unit 2. While there are some differences between the implementation of the upgrade between the two units, it is expected that the degree of the differences will be minimal. A separate activity will track these differences. These differences will be evaluated with regard to HFE by performing a delta analysis, which will assess their impact in light of the full HFE Program execution and associated documentation for Unit 1. This delta analysis will be performed as tabletop effort. This analysis will examine impacts of these Unit 2 differences to all of the activities presented in Section 6. If specific additional activities are necessary to evaluate differences (e.g., running scenarios in the simulator to validate a delta with regard to a particular feature), these will be performed as identified by this effort and documented. A single separate report will be produced describing how the Unit 2 differences were evaluated regarding HFE.

8. REFERENCES

[1] NRC. 2012. "Human Factors Engineering Program Review Model (NUREG-0711, Rev. 3)." Washington, DC: U.S. Nuclear Regulatory Commission.

[2] EPRI. 2015. "Human Factors Guidance for Control Room and Digital Human-System Interface Design and Modification: Guidelines for Planning, Specification, Design, Licensing, Implementation, Training, Operation, and Maintenance for Operating Plants and New Builds." 3002004310.

[3] Fink, R., Killian, C., Amin, J., and Naser, J. 2012. "Development of a Site HFE Program. Proceedings of the 8th International Topical Meeting on Nuclear Plant Instrumentation, Control, and Human-Machine Interface Technologies (NPIC & HMIT 2012)." San Diego, CA.

[4] EPRI. 2013. "Human Factors Engineering (HFE) Training Course for Operating Nuclear Power Plant Personnel." 300200319.

[5] NRC. 2007. "Standard Review Plan, Chapter 18 - Human Factors Engineering (NUREG-0800)." Washington, DC: U.S. Nuclear Regulatory Commission.

[6] NUREG-1764. 2007. "Guidance for the Review of Changes to Human Actions," Rev 1.

[7] NUREG/CR-6400. 1996. "HFE Insights for Advanced Reactors Based Upon Operating Experience."

[8] NUREG-1275 series, vol. 1 through 14.

[9] NUREG/CR-3331. 1983. "A Methodology for Allocation of Nuclear Power Plant Control Functions to Human and Automated Control."

[10] IEEE-1023. 2020. "Institute of Electrical and Electronics Engineers Recommended Practice for the Application of Human Factors Engineering to Systems, Equipment, and Facilities of Nuclear Power Generating Stations and Other Nuclear Facilities."

[11] NRC. 2002. "Human System Interface Design Review Guidelines (NUREG-0700). Washington, DC: U.S. Nuclear Regulatory Commission."

[12] EPRI. 2019. "Digital Engineering Guide: Decision Making Using Systems Engineering." 3002011816.

[13] AP1000, "Interface Specification for Class 1E DC Motor Operated Valves (APP-GW-J4-003)."

[14] AP1000, "Protection and Safety Monitoring System - Technical Manual," APP-PMS-J0M-003, Rev. 2.

[15] "Human Factor Engineering Detailed Design Review In-Process Audit."

[16] "Limerick Generating Station Unit 1 & 2 Turbine Control System Upgrade Display Design Functional Requirements & Implementation Guidelines." (WNA-DS-02820-GLIM, Rev. 1).

[17] "Global Instrumentation & Controls Control & Information Systems Engineering Human-System Interface Display Implementation Guidelines." (WNA-DS-04213-GEN, Rev. 1).

[18] "Human Factors Engineering Guideline for the Common Q Display System." (WNA-IG-00871-GEN, Rev. 0).

[19] NUREG-1852. 2007. "Demonstrating the Feasibility and Reliability of Operator Manual Actions in Response to Fire."

[20] Nuclear Energy Institute Efficiency Bulletin 17-06, "Implement Standard Design Change Process."

[21] Nuclear Energy Institute (NEI) IP-ENG-001, "Standard Design Process," Delivering the Nuclear Promise® Initiative.

[22] NEI Nuclear Industry Standard Process – Engineering (NISP-EN-04), "Standard Digital Engineering Process," Delivering the Nuclear Promise® Initiative.

[23] EPRI. 2007. "Minimum Inventory of Human System Interfaces," Draft Report 1015089. https://www.nrc.gov/docs/ML0800/ML080080204.pdf.

[24] ISO 9241-210. 2019. "Ergonomics of Human-System Interaction – Part 210: Human Centered Design for Interactive Systems."

[25] ISO 9241-10. 1996. "Ergonomic Requirements for Office Work with Visual Display Terminals (VDTs) – Part 10: Dialogue Principles."

[26] AP1000, "Human-System Interface Design Guidelines," (APP-OCS-J1-002, Rev. 9).

[27] NUREG-0800, Revision 3 (2016), Chapter 18, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition – Human Factors Engineering."

[28] Generic Letter 82-33 (NUREG-0737 Supplement 1).

[29] "The Limerick Updated Final Safety Analysis Report," Section 1.13.

[30] "Limerick Generating Station Units 1 and 2 Control Room Design Review Program Plan," submitted to the NRC on August 31,1983.

[31] "Philadelphia Electric Company Limerick Plant Control Room Design Review Final Report," June 1984, submitted to the NRC on August 16, 1984.

[32] "Philadelphia Electric Company Limerick Plant Control Room Design Review Supplemental Report Number 1 Final Report of June 1984," October 1984, submitted to the NRC on November 2, 1994.

[33] "Philadelphia Electric Company Limerick Plant Control Room Design Review Supplemental Report Number 2 Final Report of June 1984," provided to the NRC on June 28, 1985.

INL/RPT-22-68995

Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report

July 2022

Casey Kovesdi
Human Factors Scientist

Stacey Whitmore
Software Developer

Paul Hunton
Senior Research Scientist

Rachael Hill
Human Factors Scientist

Jeffrey Joe
Senior Human Factors Scientist

Tina Miyake
Human Factors Scientist

Jeremy Mohon
Human Factors Scientist

This document redacts proprietary information as identified by Constellation. Redactions of Constellation proprietary information are presented in the text using brackets with a superscript (C). This document contains no Idaho National Laboratory proprietary information.

Idaho National Laboratory

INL is a U.S. Department of Energy National Laboratory operated by Battelle Energy Alliance, LLC

INL/RPT-22-68995

Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report

Casey Kovesdi
Human Factors Scientist
Paul Hunton

July 2022

Idaho National Laboratory
Nuclear Science and Technology
Idaho Falls, Idaho 83415

http://www.inl.gov

Prepared for Constellation Energy Under
Cooperative Research and Development Agreement 21CRA5

REVISION LOG

Rev.	Date	Affected Pages	Revision Description
1	05/03/2023	All	Proprietary information was removed. No further changes were made to the document and pagination was preserved. When removing proprietary information from the table in Appendix D, the physical size of the table in the document was reduced by 13 pages. To maintain the same pagination as the original document, 13 blank pages were inserted at the end of Appendix D.

ABSTRACT

Constellation Energy is pursuing a safety-related instrumentation and control upgrade at their Limerick Generating Station. NUREG-0711, "Human Factors Engineering (HFE) Program Review Model" [1], is being leveraged by Constellation Energy to guide HFE activities for this project. Idaho National Laboratory (INL) is assisting Constellation Energy by facilitating HFE efforts associated with this upgrade.

INL has developed and Constellation has reviewed an accepted, INL/RPT-22-68693, "Human Factors Engineering Program Plan for Constellation Safety-Related Instrumentation and Control Upgrades" [2]. This document is being used to direct NUREG-0711 based HFE activities following a graded approach appropriate for this project.

This report captures project efforts associated with several HFE Planning and Analysis Phase activities as described in INL/RPT-22-68693[2], namely:

HFE Plan (6.1) Document Section	Activity	Section in this Document
6.5	Functional Requirements Analysis and Function Allocation	4 in its entirety
6.2	"New State" Vision for Instrumentation and Control Upgrades	4.1.1.1.1.1
6.3	Concept of Operations	4.1.1.4 and 4.2.2
6.6	Project Screening and Task Analysis	5 in its entirety
6.8	Important Human Actions	5.4
6.11	Conceptual Design Human-System Interface Display & Navigation Strategy	5.1.1.2.3
6.7	Staffing and Qualification Analysis	6
6.9	Verification & Validation: Establish Simulator Strategy to Support Integrated System Validation	7

Completion of other Planning and Analysis Phase activities are documented in separate reports listed below:

HFE Plan Document Section	Activity	Report
6.4	Operating Experience Review	Human Factors Engineering Operating Experience Review of the Constellation Limerick Control Room Upgrade: Results Summary Report, INL/RPT-22-68703 [3]
6.10	Human-System Interface Style Guide	Human-System Interface Style Guide for Limerick Generating Station, INL/RPT-22-68558 [4]

While the Planning and Analysis HFE Plan sections followed the structure of NUREG-0711, its implementation as captured in this report reflects its performance within the larger project. This report, in conjunction with References [2], [3], and [4], completes all HFE activities for the Planning and Analysis Phase as identified in INL/RPT-22-68693[2], Table 1, "Summary of NUREG-0711 Activities and their Relationship to Project HFE Activities."

Page intentionally left blank

CONTENTS

FIGURES

TABLES

ACRONYMS

AER	Auxiliary Equipment Room
ATWS	Anticipated Transient Without SCRAM
BCA	Business Case Analysis
BOP	Balance of Plant
BWR	Boiling-Water Reactor
CRS	Control Room Supervisor
D3	Diversity and Defense-in-Depth
DC	Direct Current
DCS	Distributed Control System (for this Project, Emerson Ovation® is the selected platform)
DIF	Difficulty, Importance, and Frequency (method to score operator tasks)
DW	Drywell
ECCS	Emergency Core Cooling System
EO	Equipment Operator (outside of MCR)
EPRI	Electrical Power Research Institute
FRA & FA	Functional Requirements Analysis and Function Allocation
FW	Feedwater
HA	Human Action
HFE	Human Factors Engineering
HPCI	High Pressure Coolant Injection
HSI	Human-System Interface
HSSL	Human-Systems Simulation Laboratory
HTA	Hierarchical Task Analysis
I&C	Instrumentation and Control
INL	Idaho National Laboratory
ION	Integrated Operations for Nuclear
ISV	Integrated System Validation
LGS	Limerick Generating Station
LLC	Limerick Learning Center
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LOS	Line-of-sight
LPCI	Low Pressure Coolant Injection (System)
LWRS	Light Water Reactor Sustainability

MCR	Main Control Room
MPR	MPR Associates, Inc.
MSIV	Main Steam Isolation Valve
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
NSR	Non-safety Related
OE	Operating Experience
OER	Operating Experience Review
OSA	Operational Sequence Analysis
OSD	Operational Sequence Diagram
PPC	Plant Process Computer
PPS	Plant Protection System (for this Project the Westinghouse Common Qualified [Common Q] Platform® is the selected platform)
PRA	Probabilistic Risk Assessment
PRO	Plant Reactor Operator
PWR	Pressurized-Water Reactor
RG	Regulatory Guide
RHR	Residual Heat Removal (System)
RO	Reactor Operator
RPS	Reactor Protection System
RRCS	Redundant Reactor Control System
RSR	Results Summary Report
SEG	Simulator Exercise Guide
SDV	Scram Discharge Volume
SLC	Standby Liquid Control
SME	Subject Matter Expert
SR	Safety-Related
SRV	Safety Relief Valve
SW	Service Water
STA	Shift Technical Advisor
SyRS	System Requirements Specification
SyDS	System Design Specification
TA	Task Analysis
TCO	Total Cost of Ownership

TRIPS	Transient Response Implementation Plan (Procedures) – Emergency Operating Procedure for Limerick
UFSAR	Updated Final Safety Analysis Report
V&V	Verification and Validation
VDU	Video Display Unit
WEC	Westinghouse Electric Company
WPF	Windows Presentation Foundation

Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report

1 INTRODUCTION AND OVERVIEW

Constellation, Idaho National Laboratory (INL), and Westinghouse have been collaborating to perform Human Factors Engineering (HFE) activities enveloped by the Planning and Analysis Phase shown on the left side of Figure 1.

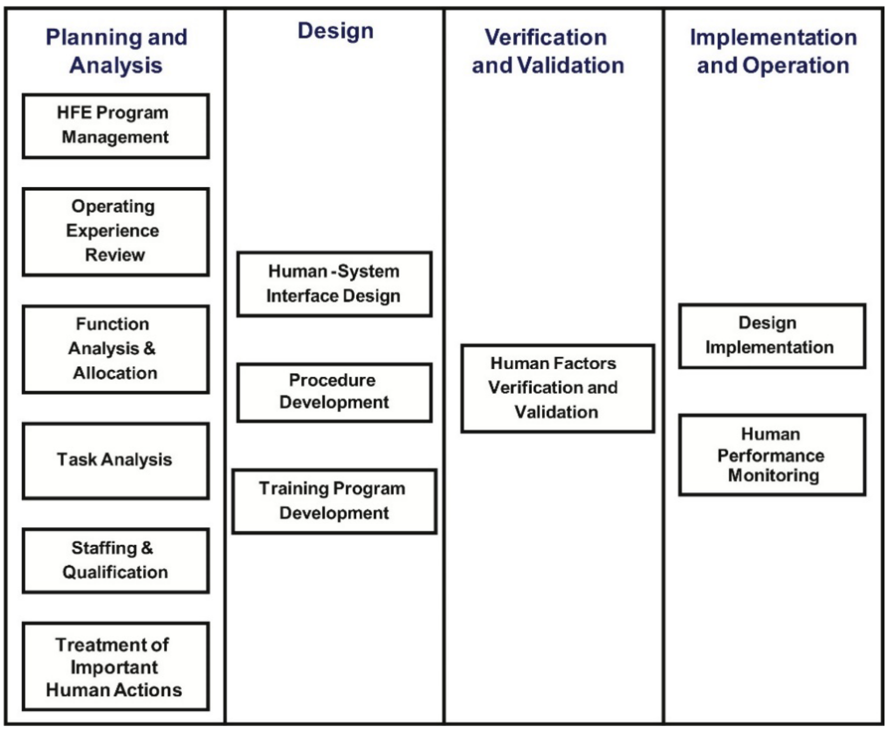


Figure 1. HFE Phases covered in NUREG-0711, Rev. 3.

INL has developed and Constellation has reviewed an accepted INL/RPT-22-68693, “Human Factors Engineering Program Plan for Constellation Safety-Related Instrumentation and Control Upgrades” [2]. Reference [2] is being used to direct NUREG-0711-based HFE activities following a graded approach appropriate for this project.

INL has also developed and Constellation has reviewed and accepted INL/RPT-22-68703, “Human Factors Engineering Operating Experience Review of the Constellation Limerick Control Room Upgrade: Results Summary Report” [3]. An Operating Experience Report (OER) Implementation Plan describing the current OER methodology is included with the Results Summary Report (RSR). Appendices are also provided that contain detailed operational experience (OE) descriptions, which contain findings and dispositional recommendations related to existing and potential human performance issues impacting the proposed safety-related instrumentation and control (I&C) upgrade design as they may impact future Limerick Generating Station (LGS) control room operations.

INL has also developed and Constellation has reviewed and accepted the "Human-System Interface Style Guide for Limerick Generating Station," INL/RPT-22-68558 [4]. This style guide provides specific guidance to design new and modified human-system interfaces (HSIs) included as part of this effort while at the same time promoting consistency in their design across the main control room (MCR) panels to the extent possible. The style guide addresses the:

- Organization and presentation of information on individual display pages on physical video display units (VDUs)
- Organization and navigation between display pages
- Design of display fonts and symbols
- Use of color coding and labeling on displays
- Design of touch for operator input if this type of HSI is desired.

The style guide also provides instructions for its use in the overall design process.

2 PURPOSE AND SCOPE

This document is an RSR that provides a description of activities performed and the results from performing the remaining NUREG-0711 Planning and Analysis Phase activities not addressed in Section 1. The activities addressed in this report not only include the Functional Requirements Analysis and Function Allocation (FRA & FA) and Task Analysis (TA) efforts for the LGS Unit 1 safety-related (SR) I&C upgrades and their impacts on the MCR, but also the other remaining Planning and Analysis activities that were completed in concert with them. This report has also been reviewed and accepted by Constellation.

This report captures project efforts associated with the remaining HFE Planning and Analysis Phase activities as depicted in Figure 1 above, namely:

- **Functional Requirement Analysis and Allocation—Section 4:** The assignment of the control and management of functions to personnel (manual control), automatic systems (automated control), and a combination of both (shared control). Taking advantage of functional control capabilities provided by the design modernization and allocating these management functions appropriately between manual and automated control will reduce human errors and inappropriate actions. This will result in higher levels of system safety and economic performance.
- **Task Analysis** (including project screening)**—Section 5:**
  - The project is screened to determine the extent of potential HFE impacts. Changes considered in project screening include those that impact operator HSIs inside the MCR, if the changes could impact human performance. Changes that do not modify HSIs, but could have other potential impact on operator tasks, are also considered in project screening (e.g., system changes that reduce the amount of time available for an operator to perform a task). This screening begins with identifying impacted human actions (HAs) and tasks and determining the nuclear safety risk for the impacted tasks and any new tasks that are safety significant.

    After assigning an initial Change Level (high, medium, or low), secondary factors are assessed and the initial HFE level may be adjusted up or down by one level based upon severity factors.
  - The TA activity analyzes the functions assigned to plant personnel in order to satisfy the requirements for successful performance. The actions personnel must do to accomplish functions assigned to them are called "tasks." Generally, the term "task" refers to a group of activities with a common purpose. The TA results are a primary consideration in designing the HSIs, procedures, and training provided to plant personnel. TA activities that occur during the Planning and Analysis Phase are presented in this report. TA also continues into the Design Phase as HSIs

are refined with final assessments occurring in the Verification and Validation Phase, as depicted in Figure 1.

- **Staffing and Qualification Analysis—Section 6:** This analysis identifies potential staffing and qualification impacts introduced by the LGS SR I&C upgrade project.
- **Treatment of Important Human Actions—Section 5.4:** This activity is concerned with the HAs most important to safety. Existing Important HAs that fall within the scope of the upgrade are identified by Constellation. Any new Important HAs are identified by a screening analysis as described in NUREG-1764, "Guidance for the Review of Changes to Human Actions" [5]. Identification of Important HAs will also be considered in a manner consistent with guidance in NUREG-0711, where applicable. Human reliability analysis then makes use of FRA & FA and TA outputs, specifications of HSI characteristics, and other inputs to identify if the legacy Important HAs are impacted by the upgrade and whether new ones are generated. Manual actions identified in the Limerick Defense-in-Depth and Diversity (D3) Common Cause Failure Coping Analysis [31] performed by Westinghouse that are credited to cope with a Plant Protection System (PPS) common cause failure are also addressed as part of this effort.

  It is important to note that the identification and treatment of Important HAs is not a standalone activity as it is woven into other HFE Planning and Analysis activities. Impacted and new Important HAs are used when screening the project as part of the TA above. The iteration of TA activities during the Design Phase may also reveal new or impacted Important HAs.

This report also captures additional project efforts associated with several HFE Planning and Analysis Phase activities described in the HFE Program Plan. These additional efforts are described in the sections of this document that best relate these additional efforts to the major HFE Planning and Analysis Phase activities shown in Figure 1. These additional project efforts include:

- New state vision for I&C upgrades—Section 4.1.1.1.1.1 under "Project Scoping:"
- Concept of operations—Sections 4.1.1.4, Initial Main Control Room Concept of Operations and 4.2.2, Workshop-Driven Main Control Room Concept of Operations Modification
- Conceptual design HSI display & navigation strategy—Section 5.1.1.2.3, Additional Inputs Created to Support the Task Analysis
- Verification & Validation—Section 7, Establish Simulator Strategy to Support Integrated System Validation (ISV)

This report, in conjunction with References [2], [3], and [4], completes all HFE activities for the Planning and Analysis Phase as identified in [2], Table 2, "Summary of NUREG-0711 Activities and their Relationship to Project HFE Activities."

3 FUNCTION ALLOCATION AND TASK ANALYSIS IN CONTEXT OF THE HUMAN FACTORS ENGINEERING PROGRAM PLAN

As part of the Systems Engineering Process, HFE activities for system upgrades as well as new designs focus on the role and function of humans as key elements in the industrial process. The human-centered analysis of systems and operations integrates the three elements of functional requirements, function allocation, and TAs to establish design requirements for an HSI design, which, in nuclear power plants, forms part of the MCR. The system and operations analysis addresses operational aspects of the plant by systematically defining equipment, software, personnel, and procedural data requirements that meet all functional objectives of the MCR and its operating crew, including safe plant operation. It assists in determining the design of the plant and specific systems, particularly the MCR HSI and its components required for safe plant shutdown.

The various phases of this analysis collect parameters concerning the plant (and its various systems) and identify those required for the operating crew monitoring, cues for action, and feedback on actions taken. The analysis also identifies the main control and operating options available to operators for safe and economic plant operation. The plant processes that should be placed under operator control, and their relationship to each other, are also revealed. Several phases of the HFE process necessary for MCR upgrades are depicted in Figure 2.

	Function Allocation →	**Task Analysis** →	**Design Activities** →	**Verification and Validation**
Goals	What is system vs. operator controlled? Identify opportunities to improve performance by indentifying modifiable functions.	What can be changed? Define information and control needs for operators to perform new and existing functions.	What's the new design? Develop conceptual designs for the HSIs.	Does it work? Test the designs and make sure all required information and controls are there and work.

Figure 2. Phases of HFE and underlying goals.

FRA & TA shown in are part of two primary activities described in NUREG-0711 [1], as part of the Planning and Analysis Phase shown in Figure 2.

The objectives of the FRA & FA element are to identify and define new and changed control functions resulting from the modernization effort that are required to satisfy plant safety and availability goals and to allocate responsibilities for those functions to personnel and automation in a way that takes advantage of human and automation strengths and avoids their limitations and weaknesses. The FRA determines the objectives, performance requirements, and constraints of the HSI design and sets a framework for understanding the role of personnel and automation in controlling plant processes impacted by the LGS SR I&C upgrade project. FRA is the assignment of functions to personnel (manual control), automatic systems (automated control), and a combination of both (shared control). Taking advantage of functional capabilities provided by the modernized safety platform (Common Q—for the PPS) and non-safety platform (Ovation—for the distributed control system [DCS] platform) and allocating these functions appropriately between manual and automated control will reduce human errors and inappropriate actions, resulting in improved system safety and economic performance.

Using the results from FRA & FA, the objective of TA is to evaluate personnel tasks (i.e., functions allocated to the human) in sufficient detail to permit the identification of the requirements for task performance (e.g., the alarms, information, controls, procedures, and training needed to perform the tasks). TA results have many uses in subsequent analyses, including staffing, error analysis, HSI and procedure design, training, and V&V. Following a graded approach, the level of detail necessary can be tailored accordingly, as described in Electric Power Research Institute (EPRI) 3002004310 [6]. The following task aspects are assessed as part of a graded approach to determine the level of analysis for Important and non-Important HAs:

- Alerts and alarms
- Decision-making
- Response requirements

- Teamwork and communication
- Cognitive and physical workload and concurrent tasks
- Need for task support
- Workplace factors, such as ingress, egress, and other physical ergonomic factors
- Environmental or physical hazards that may affect operators.

Because of the close relationship and interdependence between functions and tasks, it is possible to combine FRA & FA and TA. The combined approach focuses on the human and system performance requirements that must be met to fulfill the functions of the system. Hence:

- The FRA & FA methodology used is described in Section 4.1, and the results are presented in Section 4.2 (summary results) and Appendix A—detailed results.
- The TA methodology used is described in Section 5.1, and the results are presented in Section 5.2 (summary results) and Appendix B—detailed results.

4 FUNCTIONAL REQUIREMENTS ANALYSIS AND FUNCTION ALLOCATION

4.1 Method

FRA is the assignment of the control and management of functions to personnel (manual control), automatic systems (automated control), and a combination of both (shared control). Taking advantage of the functional control capabilities provided by the design modernization and allocating these management functions appropriately between manual and automated control will reduce human errors and inappropriate actions. This will result in improved system safety and economic performance.

The allocation of control functions to either machines or humans can be determined by a number of factors, such as:

- Technology capability and limitations (i.e., technical feasibility)
- Human capability and limitations
- Operational requirements
- Nuclear safety requirements
- Equipment protection requirements
- Regulatory requirements
- Organizational requirements
- Cost, productivity, and economic factors
- Guidance for allocation of control functions is provided in NUREG/CR-3331, “A Methodology for Allocation of Nuclear Power Plant Control Functions to Human and Automated Control” [7].

This FRA & FA methodology is based upon:

- The principles described in NUREG-0711 [1].
- Section 3.3 of EPRI report, "Human Factors Guidance for Control Room and Digital Human-System Interface Design and Modification: Guidelines for Planning, Specification, Design, Licensing, Implementation, Training, Operation, and Maintenance for Operating Plants and New Builds" [6], which provides HFE guidance for control room design and modification
- IEEE-1023, "Recommended Practice for the Application of Human Factors Engineering to Systems, Equipment, and Facilities of Nuclear Power Generating Stations and Other Nuclear Facilities" [8], which provides recommendations for applying HFE
- The EPRI "Human Factors Engineering (HFE) Training Course for Operating Nuclear Power Plant Personnel" [9]
- INL/EXT-21-64320, "Development of an Assessment Methodology That Enables the Nuclear Industry to Evaluate Adoption of Advanced Automation" [10].

A graded approach was followed so only FRA & FA activities needed for the modification were performed. A major benefit of applying the graded approach is elimination of unnecessary work with assurance that all necessary HFE activities are complete.

Changes in the allocation of function management to personnel or automated systems (i.e., changes in the level of automation) were identified. The reason is that changes in the control of functions and allocations may impact the conceptual design and personnel roles, responsibilities and workload. FRA & FA are methods are applied to identify new and changed functions and to allocate them between automation and personnel.

Functions that are addressed in these evaluations included not only process control and protection functions but also other required functions, such as collecting data, evaluating or comparing data, tracking parameters over time, calculating values, retrieving needed information displays, and other secondary tasks. Decisions on what automation features have been included in the design included addressing these functions and their impact on personnel workload and potential for human error. New technology features, as incorporated, create opportunities to reduce burden on operators and maintenance technicians as well as improve human performance.

FRA & FA results, as captured in Section 4.2 and Appendix A, were used by the HFE team and other engineering groups involved in the modernization effort, such as with the TA element. The results will be also applied to subsequent elements in the design process (e.g., HSI design and HFE V&V). Figure 3 provides an overview of the FRA & FA process based on EPRI 3002004310 [6] (Section 3.4.4) and INL/EXT-21-64320 [10] (Section 5.2).

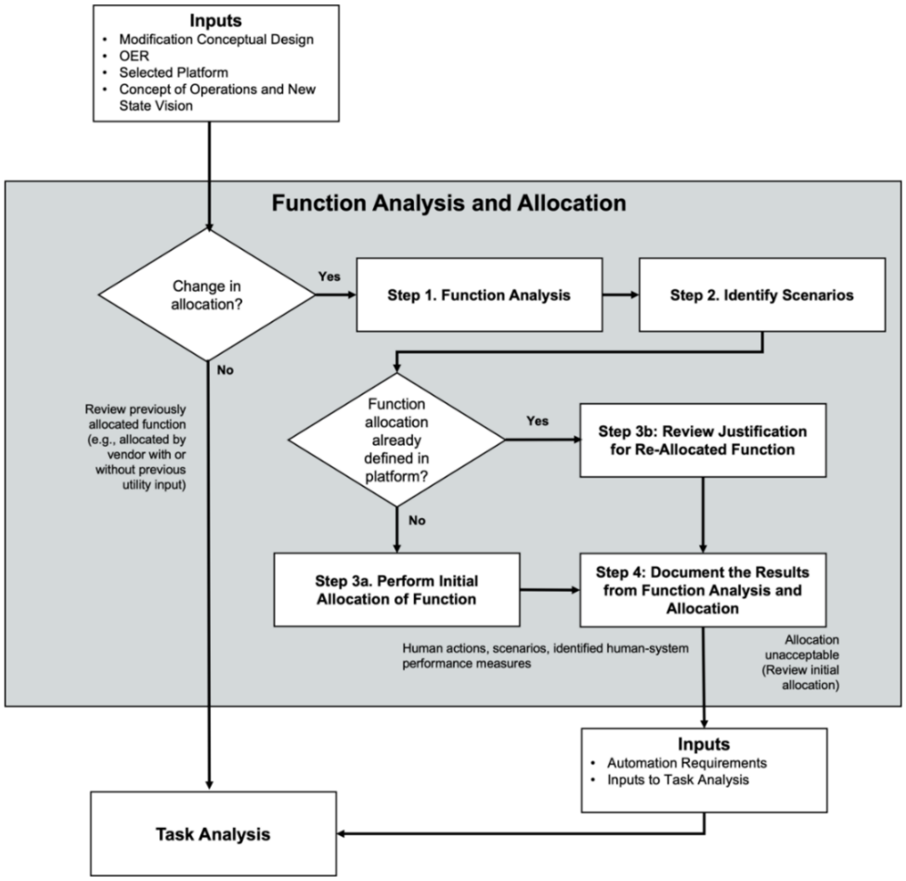


Figure 3. FRA & FA overview.

4.1.1 Inputs to Functional Requirements Analysis and Function Allocation

The allocation of functions to either machines or humans can be determined by a number of factors, such as:

- Technology capability and limitations (i.e., technical feasibility)
- Human capability and limitations
- Operational requirements
- Nuclear safety requirements
- Equipment protection requirements
- Regulatory requirements
- Organizational requirements
- Cost, productivity, and economic factors.

All of these factors are normally considered already during the FRA to ensure that resources are applied in the most cost-effective manner.

Resulting from an assessment of these factors, each function allocation opportunity would be determined by the following criteria (based primarily on principles described in NUREG/CR-3331 [7]):

- Need for alarm handling
- When large amounts of data must be stored
- Need for extensive data analysis or calculation
- Availability of proven technology
- Need for auto configuration
- When it is consistent with design practice
- When decision-making is too complex for humans (e.g., based on complex calculations)
- When events occur too rapidly for the human to respond
- When the operating crew prefers automation
- When complex sequences must be controlled
- When it would be too costly for human operation.

The following are indications for potential human control of all or part of a process:

- When automation is not feasible or too costly
- When the system can provide adequate cognitive support
- When the process is not excessively difficult
- When human operation will provide job satisfaction
- When it is a regulatory or policy requirement.

When operators prefer to control the process and such control can be proven to be reliable. When all the functions have been evaluated, there are often a number of tradeoffs made to motivate a decision for either automation, humans, or shared between the two, as for example depicted in Table 1. These tradeoffs need to be evaluated before starting any system or HSI design activity.

Table 1. Function allocation tradeoffs.

Criterion	Description
Engineering tradeoffs	Are there obvious improvements in engineering and design that would reduce human factors cost? Are there technology costs that could be reduced by allocation to the operator?
Technical feasibility	Can technology be developed in time? Are costs acceptable?
Technical consistency	Check for gross imbalance of technology between human and machine.
Balance of cost	Have designers increased system cost by overemphasizing technology? Have designers increased human cost by underexploiting technology?
Cost sustainability	Can costs for both systems and humans be sustained over the lifecycle of the project?

In 2020, Constellation entered a public-private partnership with U.S. Department of Energy's Light Water Reactor Sustainability (LWRS) to explore the feasibility of performing a pilot SR I&C upgrade project at LGS. LWRS research directly contributed to the execution of the project initial scoping phase of the LGS SR I&C effort. The "LWRS Safety-Related Instrumentation & Control Pilot Upgrade Initial Scoping Phase Implementation Report and Lessons Learned," INL/EXT-20-59809 [11], provides a detailed summary of this multimillion-dollar effort.

The FRA & FA considerations objectives, as described above, were generally taken into account during the initial scoping phase of the Limerick SR I&C upgrade project. This is further discussed in Section 4.1.1.1 below.

4.1.1.1 Modification Project Initiation Phase Scoping and Vendor Selection

4.1.1.1.1 Light Water Reactor Sustainability Project Research as Applied to Project Scope

4.1.1.1.1.1 New State Vision

LWRS Program Plant Modernization Pathway is oriented around properly applying digital upgrades in a manner that maintains or improves safety, improves plant operational performance, and reduces operating and maintenance costs to enhance economic viability. An LWRS research document that addresses this effort is INL/EXT-19-55852, “Nuclear Power Plant Modernization Strategy and Action Plan” [12]. Further efforts to expand and refine the nuclear plant operating model transformation presented in this document are being pursued under Integrated Operations for Nuclear (ION) Research. ION is generically described in INL/EXT-20-59537, “Analysis and Planning Framework for Nuclear Plant Transformation” [13].

The new state vision model shown in Figure 4 is an adaptation of a similar figure from INL/EXT-19-55852 [12]. This concept was applied to the LGS SR I&C upgrade effort to guide initial scoping research activities to ensure that plant and work function modernization enabled by the LGS SR I&C upgrade achieve strategic business objectives while at the same time maintaining and enhancing safety and operational performance.

Figure 4. Limerick SR I&C Upgrades in the Context of ION.

Nuclear power plant budgets are created using a market-based electricity price point to derive total operating, maintenance, and support costs to support this price (top down). Work is also analyzed for opportunities to aggressively focus workload on essential functions that can be resourced within available budgets (bottom up). Work functions are then configured into the operating model. Process innovations and technologies are then applied as an integrated set by using systems engineering and HFE. This promotes a business-driven digital transformation strategy that reformulates the traditional labor-centric model to one that is technology-centric. This transformation lends itself to fewer onsite staff focused on daily operations, and increasing plant safety, reliability, and situational awareness. The transformation strategy, along with process changes, supports employing centralized maintenance and support functions or outsourcing these functions to on-demand service models.

A tenet directing the larger digital transformation strategy in general, and the Limerick SR I&C upgrade project in particular, is that the replacement of current equipment is not to simply to provide like-for-like functionality when compared to the existing equipment. Instead, digital upgrades are undertaken to fully leverage the capabilities of the technology as part of a holistic effort to establish a "New State" that reduces the Total Cost of Ownership (TCO) for facilities that deploy them for the balance of the plant operating period.

4.1.1.1.1.2 Project Scope Bounded

It was during the project initiation phase that the scope of the Limerick SR IC upgrade was established. This scope is outlined in Figure 4 in red and includes:

- A common, SR, PPS platform that will implement the functions of the following boiling-water reactor (BWR) systems as applications:
  - Reactor Protection System (RPS)
  - Nuclear Steam Supply Shutoff System—also referred to as the Primary Containment Isolation System in other BWRs
  - Emergency Core Cooling Systems (ECCS)
- A Non-Safety Related (NSR) platform to host the existing SR Redundant Reactivity Control System (RRCS) function. In accordance with 10 CFR 50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants" [14], the RRCS must remain fully independent of the PPS (transmitters may be shared) but does not have to be constructed of SR components. Consequently, the RRCS will be upgraded using an NSR DCS. This DCS is expected to host most of the NSR functions in the unit. This includes a segment of DCS to receive data from the PPS and perform the channel check function, alerting the operator to significant disagreements in PPS and RRCS inputs.

MCR upgrades to implement the above-mentioned scope are also included in the Limerick SR I&C upgrade project.

At that time, a tenet was established that both the PPS and the NSR DCS are to be expandable. The PPS and NSR DCS are intended to become the "target platforms" onto which the functions of other obsolete I&C systems are migrated. Over time, the number of diverse I&C systems will be substantially reduced. By digitizing I&C plant information and passing it unidirectionally to other data networks, remote monitoring and data analytics capabilities are enabled to further reduce facility TCO. Coordinating I&C technology upgrades with training simulator upgrades also reduces facility TCO. These opportunities are reflected in the red text items in Figure 4.

4.1.1.1.1.3 Light Water Reactor Sustainability Program Research Products for Bounded Scope

4.1.1.1.1.3.1 Functional Requirements Baselines

MPR Associates, Inc. was subcontracted by the LWRS Program to lead the authoring of two vendor-independent functional requirements baseline documents based upon the LGS scope identified above, including:

- An SR PPS platform and application functional requirements baseline (Appendix A to INL/EXT-20-61079, "Vendor-Independent Design Requirements for a Boiling Water Reactor Safety System Upgrade" [15])
- An NSR DCS platform requirements and application requirements baseline for the RRCS (Appendix B to INL/EXT-20-61079 [15]).

MPR coordinated extensively with engineering, operations, training, simulator, and licensing personnel from LGS and with LWRS researchers in the creation of the functional requirements baselines. As an LWRS research product, these baseline documents are generally intended for use by the larger nuclear industry. They were tailored to the LGS plant design and reflect design concept decisions made by LWRS research and LGS design participants to achieve objectives associated with LGS Digital Transformation plans.

4.1.1.1.1.3.2 Business Case Analysis

As part of the initial scoping phase, ScottMadden and Associates was subcontracted by the LWRS Program to lead the authoring of INL/LTD-20-59707, "Business Case Analysis for Digital Safety-Related Instrumentation & Control System Modernizations" [16]. ScottMadden and Associates analysts worked with personnel from the Constellation LGS, MPR, and LWRS to produce it.

This research product illustrates a methodology for utilities considering a digital modernization of I&C systems to evaluate cross-functional labor and material benefits and conduct a financial analysis as part of the development of the overall business case for digital modernizations. The objectives of this research product include:

- Providing a bottom-up approach to:
  - Establish labor and material costs for the current systems within the defined I&C upgrade scope
  - Identify expected labor and material benefits enabled by the upgrade design concept
  - Validate the expected benefits with SMEs
- Demonstrating the methodology used to perform a detailed financial analysis, including:
  - Estimation of annual benefits related to organizational workload reductions for both online and outage work, including both quantitative benefits (which were included in the BCA result) and qualitative benefits (which were identified as areas of additional potential savings but were not included in the BCA result)
  - Estimation of annual benefits related to materials and inventory expenditures
  - Valuation of avoided lifecycle costs associated with escalation of material expenditures
  - Valuation of the modernization over the lifecycle of the Station
- Illustrating the scale of benefits that can be expected from a modernization of SR I&C systems at a two-unit BWR nuclear power station
- Providing example worksheets and templates to support a BCA of similar efforts by other utilities
- Providing lessons learned and opportunities for utilities that might subsequently implement a similar digital modernization effort. These are specifically identified in Appendix A to INL/LTD-20-59707 [16].

This methodology, when specifically applied to the LGS for Constellation as part of the initial scoping phase of the LGS SR I&C upgrade, produced results used as an input to the Project Economic Analysis developed by Constellation, as described in Section 4.1.1.2.2. A nonproprietary version of INL/LTD-20-59707 [16] created for public release is captured in INL/LTD-20-59707, "Business Case Analysis for Digital Safety-Related Instrumentation & Control System Modernizations" [17].

4.1.1.2 Constellation use of Light Water Reactor Sustainability Research Products

4.1.1.2.1 Performance Specification and Vendor Selection

While the functional requirement baseline documents, as described in Section 4.1.1.1.1.3.1, are informed by the design requirements of the LGS facility, they were not tailored to best apply to the specific project requirements for Constellation. In order to tailor the functional requirements baseline information to LGS, the information provided by them was reformulated by Constellation into a LGS-specific performance specification.

A performance specification defines the functional requirements for the system, the environment in which the system operates, and interface characteristics. The performance specification does not describe how a requirement is to be achieved. Constellation believed that this would allow the vendors an opportunity to provide their best design and most cost-effective solution, since the research team members outside of Constellation were not intimately aware of vendor products being offered because of vendor proprietary information constraints.

The performance specification provided a high-level system hierarchy and all the criteria that prospective vendors would be graded against, in accordance with the EPRI Digital Engineering Guide [20], Section 5.1.1. The performance specification used most of the requirements developed in the functional requirement baseline documents. The performance specification was further vetted and revised to address comments from potential vendors and Constellation stakeholders, including engineering and operations, to ensure that the solution being solicited was correct for the subject station. The performance specification conveys a clear understanding of what the system is supposed to do and what remains to be designed.

The use of the performance specification provides the foundation of documenting required operational capabilities into an integrated system design through the concurrent consideration of all lifecycle needs. The specification provided a robust, systems engineering approach that balances total system performance and total ownership costs. Leveraging the functional requirements baseline research documents described above and utilizing the systems engineering process allowed Constellation to describe the solution required to meet LGS needs.

The performance specification was used by Constellation to solicit proposals from vendors. The ability of the solicited vendors to provide a system conforming to the performance specification was a critical metric used to select the vendor for this project. Westinghouse was selected by Constellation based on their capability to best meet the performance specification while providing an elegant solution.

4.1.1.2.2 Project Economic Analysis and Project Approval

The Constellation Initiation Phase internal Project Economic Analysis is founded on the LWRS BCA research (References [16] and [17]), as summarized in Section 4.1.1.1.1.3.2. This provided more well-rounded and detailed material and labor cost data to evaluate the monetary benefit that digital modernization and pursuing the PPS Project can enable. This permitted adjusting those benefits as sensitivities to the base business case assumptions and evaluating the influence on the Project Net Present Value. Westinghouse cost estimates based upon their proposal were also factored into the Project Economic Analysis.

Constellation developed a resource loaded project schedule during the late stages of the Project Initiation Phase. The primary goal was to baseline the project schedule from a work breakdown structure developed from:

- Nuclear Energy Institute (NEI) “Standard Design Process,” IP-ENG-001 [18]
- NEI “Standard Digital Engineering Process,” NISP-EN-04 [19]

- EPRI Digital Engineering Guide [20]
- Digital Instrumentation and Control Interim Staff Guidance (I&C-ISG-06), Revision 2, License Amendment Request [21] Alternate Review Process.

This also provided early insight into resource demands from reviewing resultant resource histograms and influenced the project staffing plan. This effort was also used to validate that project costs were bounded as required by Constellation business practices. As a result of the summation of all this work, Constellation management authorized the project to proceed into concept and detailed design phases.

4.1.1.2.3 Creation of Requirements, Design Specifications, and Other Necessary Inputs

The requirements contained in the performance specification were used by the selected vendor (Westinghouse) as a starting point for the System Requirements Specifications (SyRSs). The tables of information were controlled using Microsoft Office products to support the migration to a requirements management system. The following SyRSs are Westinghouse deliverables that have been provided as inputs for the FRA & FA effort described in this report.

- WNA-DS-04899-GLIM: Plant Protection System SyRS [22]
- WNA-DS-05080-GLIM: Distributed Process Control System SyRS [23].

The two documents above, along with other inputs were used to create the System Design Specifications (SyDS) which have also been provided as inputs for the FRA & FA effort described in this report.

- WNA-DS-04900-GLIM: Plant Protection System SyDS [24]
- WNA-DS-05079-GLIM: Distributed Process Control System SyDS [25].

The documents above (in draft form) provided baseline information to INL for this FRA & FA effort. Others that augmented the information provided in the SyRS and SyDS included:

- Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project [26] (in draft form)
    - Describes the extent of modifications that will be completed as part of the upgrades and summarizes key functional changes to the plant systems affected under this upgrade
- LTR-AMER-MKG-21-656, Rev. 2, Appendix A.9 [27]
    - Describes the new automated operator control aids that will be part of the upgrades and specific operator aids for each of the impacted systems.

As the HSI design matures during the Design Phase shown in Figure 1 above, Westinghouse and Constellation will update design documentation as appropriate to fully describe the HSI design attributes resulting from HFE efforts being accomplished to support the LGS SR I&C upgrade project. All design documentation will be incorporated as inputs into subsequent HFE efforts.

4.1.1.3 Operating Experience Review

An HFE Operational Experience Review (OER) [3] was performed for LGS in accordance with Section 6.4 of the "Human Factors Engineering Program Plan for Limerick Safety-Related I&C upgrades Instrumentation and Control Upgrades" [2]. The OER methodology applied was based on NUREG-0711, Rev. 3 [1] review criteria, guidance in EPRI Technical Report 3002004310 [6] and the process and results from prior INL OE studies with several other utilities as described in References [28] and [29]. Some of the results from the OER include:

- In the conduct of operations, there is a pilot-copilot relationship and coordination between reactor operator (RO) and plant reactor operator (PRO), which influences current design decisions, such as the location of the existing SR I&C displays and controls and SR VDU location.
- The crew performs their jobs well, keeps the plant safe, and are aided by I&C systems that give them complete and accurate information in a timely manner. In the past, when information was incomplete, their ability to make accurate diagnoses and perform the correct actions to respond to the situation was challenged. Similarly, when information was delayed, or in particular, when information was provided at a high through rate, operators were at times challenged to keep up with the pace of the event.
- Among operators, automation is a highly desired feature in future MCR designs. While there is little current OE with automation in the nuclear industry, lessons learned in other industries and domains identify important OE issues.
- Other issues with relevance for human performance, such as situational awareness, communications, display features, and behaviors, etc., were also identified.

This and other pertinent OER information were used as inputs to the FRA & FA, as described in Section 4.1.3, and to the TA, as described in Section 5.1.1.1.

4.1.1.4 Initial Main Control Room Concept of Operations

INL HFE researcher experience is based primarily on pressurized-water reactor (PWR) technology and operations techniques. Generically, the concept of operations for a PWR MCR as understood by INL HFE researchers is that it is "linear" for both normal operations and casualty response. In this case, linear is that, during both normal and casualty response, plant operations are directed by procedures that are typically executed step-by-step in order based upon either when performing routine evolutions in the plant or during casualty operations, such as in response to a large-break loss of coolant. Such a concept of operations is amenable to the organization and presentation of digital displays on VDUs in a hierarchical format that complements linear procedure execution to optimize the use of available VDUs and operator performance.

Voice communications between operators are also particularly structured and formal in such an environment. As steps are executed linearly, there is a three-way communication technique normally employed between the MCR Control Room Supervisor (CRS) and RO where:

- The CRS gets the attention of the RO and communicates an order.
- The RO repeats the order back to CRS.
- The CRS acknowledges the that the order has been correctly received and interpreted by the RO.
- The RO then performs the order.

The INL understanding of linear procedure execution coupled with three-way communication is consistent with the understanding of Westinghouse personnel assigned to this project. Consequently, it was the expectation of both INL and Westinghouse personnel that the concept of operation for Limerick (a BWR) would be similar.

The result of this thinking was the assumption that the organization and presentation of digital displays on VDUs for this project would be in a hierarchical format for both normal operation and casualty response and that the linear three-way communication strategy would be strictly employed in the Limerick MCR. As described in Section 4.2.2, this initial concept of operations was altered as a result of the FRA & FA workshop.

4.1.2 Step 1—Functional Requirements Analysis

FRA identifies and defines new and changed functions that support the higher vision and first principles for improved plant operation and describes the functions of interest in sufficient detail as to perform a review of function allocation decisions and evaluate subsequent impacts. Also, the HAs impacted by the reallocation are identified, described, and documented. In the same manner, new HAs that emerge from reallocated functions require identification, description, and documentation as well.

FRA was initiated through a planning meeting and continued collaboration occurred between LGS operations, engineering, and INL HFE. This drove the analysis and prioritization of the information identified from the inputs. Specific items pursued included:

- Screening tasks based upon:
  - Whether they were impacted by the modification or not (changes in function)
  - Whether there were tasks that address operator actions identified either as part of the D3 analysis [31] or are considered "risk important actions" from the LGS Updated Final Safety Analysis Report (UFSAR), Chapter 15 [30] or the Limerick Generating Station Probabilistic Risk Assessment (PRA) Summary Notebook, Revision [41]
- Screening and prioritization of tasks impacted by the upgrade based on task difficulty, importance, and frequency (DIF) scores as provided by LGS and captured in Appendix C
- Selecting scenarios that provide maximum "Integrated System Validation coverage" for the "high priority screened tasks" identified directly above
- Request specific inputs from Constellation that INL could review to support FRA & FA:
  - Explanation of DIF scores and associated training criteria
  - Drill guides (simulator instructor instructions) for selected scenarios
  - Procedures that will be used in execution of selected scenarios
  - The list of all "risk important actions" and the identified time frames for execution.

The results of the meeting identified two primary inputs for review: Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project [26] and LTR-AMER-MKG-21-656, Rev. 2, Appendix A.9 [27]. Subject matter experts (SMEs) in operations from LGS reviewed all of the known tasks performed within the MCR and screened the tasks being impacted by the SR I&C upgrade project. The screened tasks were then mapped to whether they were part of the UFSAR Chapter 15 events [30], D3 analysis [31], or the PRA [41] defining these tasks as Important HAs. All identified impacted Important HAs were considered for subsequent analysis. Non-Important HAs were further screened based on their DIF score, among other operational characteristics, to be grouped in specific operational use cases (i.e., scenarios). The scenarios were defined by operational SMEs at LGS and were documented in SEGs. One or more impacted tasks could be part of a given scenario. The results of the function-to-task mapping and screening are documented in Appendix C.

4.1.3 Step 2—Identify Scenarios

Operations SMEs from LGS developed scenarios for each impacted function and task impacted by the SR I&C upgrade. Each scenario grouped the impacted tasks together in a contextually appropriate way. For instance, tasks are rarely performed in isolation. In many cases, the functions and tasks to be performed are part of a broader plant event (e.g., managing an ATWS). Using scenarios, the analysis of impacted functions and tasks can account for different operational contexts that are important when understanding how any given function or task affects related tasks.

A total of nine scenarios were identified by LGS SMEs. To aid in the proper allocation of functions within the HSI design and associated tools used by operating personnel, the following activities were performed for scenario identification:

- Identify significant events, scenarios, and procedures impacted by the Limerick Unit 1 SR I & C upgrade scope in which functions and operator tasks will change
- Evaluate the large number of events, scenarios, and procedures expected to be identified
- Select the events, scenarios, and procedures expected to have the largest positive and negative impacts on operator and system performance
- Describe the events, scenarios, and procedures in sufficient detail that they can be evaluated.

Criteria considered during the selection of scenarios included:

- Providing the greatest operator error traps and opportunities for human error and poor performance
- Offering the greatest opportunity for improved safety and economic performance
- Involving changes from manual to shared or automatic functions
- Involving the most changes in operator roles and responsibilities
- Involving increased operator workload and reduction in operator action times.

Events, scenarios, and procedures identified during OER were retained because they met the criteria above and provide continuity throughout the HFE Program execution:

- Scenario #1: [ ](C)
- Scenario #2: [ ](C)
- Scenario #3: [ ](C).

The complete FRA & FA scenario list below included those carried over from the OER in **bold**:

- Scenario #1: [ ](C)
- Scenario #2: [ ](C)
- Scenario #3: [ ](C)
- Scenario #4: [ ](C)
- Scenario #5: [ ](C)
- Scenario #6: [ ](C)
- Scenario #7: [ ](C)
- Scenario #8: [ ](C)
- Scenario #9: [ ](C)

These scenarios are documented in detail in the SEGs. The TA activities described in Section 5 also used these scenarios as the basis for analysis. It is expected that these scenarios will be carried forward into ISV to have a baseline to assess the maturing design's capability as the HFE Program is performed.

4.1.4 Step 3—Perform Functional Allocation

Because there was an already defined allocation of function for the SR I&C upgrade (e.g., see FRA & FA inputs in Section 4.1.1), Substep 3b (Review Justification for Re-Allocated Functions) from Figure 3 above was performed. Specifically, the function allocation analysis consisted of scenario observations at the LGS simulation facility shown in Figure 5 using the nine scenarios identified.

Figure 5. Constellation Limerick MCR simulator.

The scenarios were performed by licensed operators from LGS while human factors engineers from INL observed, collected notes, and facilitated a suite of semi structured interview questions. The specific protocol used is described next.

4.1.4.1 Protocol and Data Collection Tools

4.1.4.1.1 Objectives

The purpose of this workshop was to understand the positive attributes and/or challenges associated with performing tasks using the current HSIs impacted by the upgrade. This information was used to ensure the new HSIs provided by the upgrade improve operator performance and support improved plant operation.

4.1.4.1.2 Design Team

The members of the design team that executed the FRA & FA workshop are identified in Table 2.

Table 2. FRA & FA design team.

Idaho National Laboratory (INL)	Constellation Limerick Generating Station (LGS)
Paul Hunton (I&C and Human Factors) Jeffrey Joe (Human Factors) Casey Kovesdi (Human Factors) Rachael Hill (Human Factors)	Paul Krueger (Operations Support) Wes Henne (RO) Keven Corey (RO) Bob Braun (CRS) Matt Jones (CRS) Sagar Patel (CRS) Eric Rosa (Operations Training) Rachel Fernandez (Training) Scott Schumacher (Site Engineering) Mark Samselski (Design Engineering) Dave Molteni (Site Engineering)

4.1.4.1.3 Agenda

The agenda for the multiday FRA & FA workshop:

DAY 1 – MARCH 22, 2022			
Time (Eastern)	**Activity**	**Location**	**Role**
08:00–08:15	**Arrive at LGS** INL arrived at LGS training facility.	LLC Room 117	All
08:15–9:30	**Introductions and Overview of the LGS Digital Upgrade Project** Introductions were made, a safety brief given, overall workshop agenda provided, and an overview of the LGS Digital Upgrade Project given to align the team on: 1. **The scope of this upgrade**, including the impacted systems, changes to controls and indications, and automation enhancements that are part of the upgrade 2. **The HFE Program Plan and introduction to FRA & FA**, including what activities have been completed, how their results are used for FRA & FA (including related documents), what the key FRA & FA outputs and related downstream HFE activities are, as well as a schedule overview 3. **The FRA & FA and workshop goals**, specifically providing an overview of the FRA & FA methodology and reminding the team that the workshop was intended to evaluate the impacts of technology (NOT THEM) and that the data was anonymized through participant identification (ID) and data aggregation where possible	LLC Room 117	1. LGS (Paul K) 2. INL (Jeffrey) (Casey)
9:30–12:00	**Perform Scenario Observations for Scenario 1** • Approximately 2 hours for each scenario with 30–60 minutes discussion each	Training Simulator/ LLC Room 117	All
12:00–12:30	**Lunch**	Training Simulator/	All

DAY 1 – MARCH 22, 2022			
Time (Eastern)	**Activity**	**Location**	**Role**
		LLC Room 117	
12:30–16:30	**Perform Scenario Observations for Scenarios 2–3 (Cont.)** • Approximately 2 hours for each scenario with 30–60 minutes discussion each	Training Simulator/ LLC Room 117	All
16:30–17:00	**End of Day Recap**	LLC Room 117	All
Note 1: Breaks were taken as needed. Note 2: All times were approximate. Note 3: INL arrived at 07:30 for orientation in the LGS simulator with Paul Krueger.			

DAY 2 – MARCH 23 2022			
Time (Eastern)	**Activity**	**Location**	**Role**
08:00–12:00	**Perform Scenario Observations for Scenarios 4–5** • Approximately 2 hours for each scenario with 30–60 minutes discussion each	Training Simulator/ LLC Room 117	All
12:00–12:30	**Lunch**	Training Simulator/ LLC Room 117	All
12:30–16:30	**Perform Scenario Observations for Scenarios 6–7 (Cont.)** • Approximately 2 hours for each scenario with 30–60 minutes discussion each	Training Simulator/ LLC Room 117	All
16:30–17:00	**End of Day Recap**	LLC Room 117	All
Note 1: Breaks were taken as needed. Note 2: All times were approximate.			

DAY 3 – MARCH 23 2022			
Time (Eastern)	**Activity**	**Location**	**Role**
08:00–12:00	**Perform Scenario Observations for Scenarios 8–9** • Approximately 2 hours for each scenario with 30–60 minutes discussion each	Training Simulator/ LLC Room 117	All
12:00–12:30	**Lunch**	Training Simulator/ LLC Room 117	All
12:30–14:30	**Perform Scenario Observations for Scenarios 8–9 (Cont.)** • Approximately 2 hours for each scenario with 30–60 minutes discussion each	Training Simulator/ LLC Room 117	All
14:30–16:30	**Wrap-Up Discussion** • Final discussion of impacted functions exercised during the scenarios was performed to verify: - Collected information was accurate and complete - Any additional impacts to the physical layout identified from the scenarios were captured	Training Simulator/ LLC Room 117	All

DAY 3 – MARCH 23 2022			
Time (Eastern)	**Activity**	**Location**	**Role**
	- Representative displays (e.g., using Plant Process Computer (PPC) for the common scenarios) were identified to prepare for the TAs workshop • Action items were captured and distributed to the team.		
Note 1: Breaks were taken as needed. Note 2: All times were approximate.			

4.1.4.1.4 Detailed Methods

The following section provides details of the key activities identified from the agenda above.

4.1.4.1.4.1 Introductions and Overview of the LGS Digital Upgrade Project

LGS engineering and INL HFE personnel provided an overview of LGS SR I&C upgrade project and HFE activities through the following activities:

- Design team introductions
- A safety brief
- Overview of the workshop agenda:
  - A project overview
  - An HFE overview
  - An FRA & FA overview
- A reminder to operators that:
  - Their participation was requested because of their knowledge and expertise.
  - The information they provided would be used to guide the HSI design.
  - Their opinions guided preferences and requirements for the new designs.
  - The collected information would be used to design or evaluate the HFE aspects of the HSIs and **NOT to evaluate their performance**.
  - The anonymity of personnel would be maintained.
  - Their comments would be treated as anonymous and coded using a Participant ID scheme.

4.1.4.1.4.2 *FRA & FA Workshop General Workflow including Scenario Observations*

Figure 6 highlights the workflow completed during this workshop.

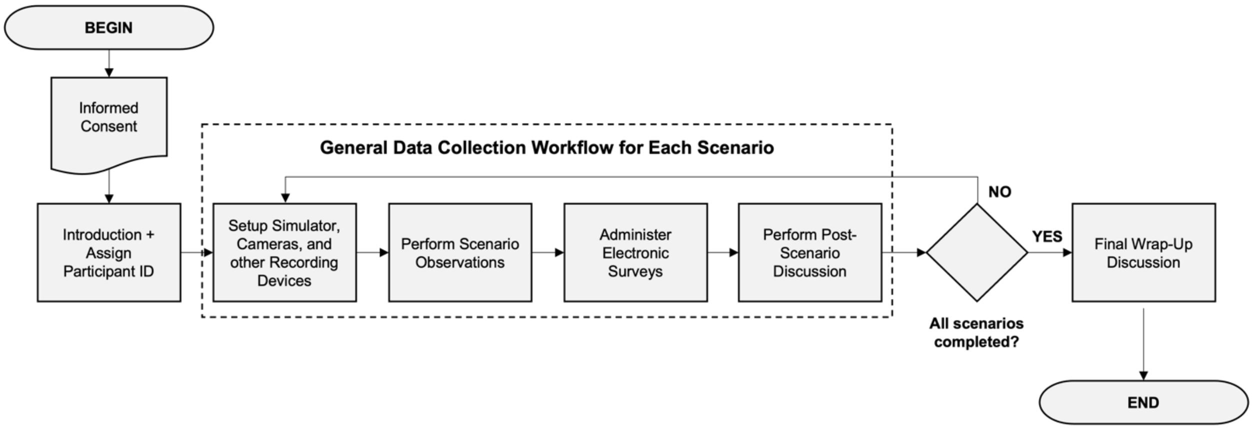


Figure 6. FRA & FA Workshop general workflow.

4.1.4.1.4.3 *Informed Consent*

Human factors staff administered printed copies of the informed consent form to participating operators and gave a brief introduction to the scenario observations upon signing.

4.1.4.1.4.4 *Introduction and Participant ID Assignment*

Operators were briefly introduced to the general workflow (Figure 6 above). During this time, LGS provided supporting details to help operators align with the objectives of these observations and expectations when performing these scenarios. While introductions were performed once, the reminders above were given as often as necessary to ensure operators were aligned with workshop goals. Human factors staff recorded participant IDs in a table. These IDs were used throughout the course of this workshop.

4.1.4.1.4.5 *Simulator and Data Collection Setup*

LGS simulator and training staff prepared the simulator for each scenario by setting up initial conditions and other tasks necessary to run the scenario and enable video recording. The simulator instructor was reminded to provide a cue when the scenario was going to begin (e.g., "in role") and end (e.g., "you are no longer in role"). Each INL staff member was assigned different primary roles for collecting notes. Human factors staff prepared the data collection tools, including a logger to collect observational and self-report data during the scenario. INL staff endeavored to not interfere with the plant operators when they were "in role." This was to allow INL staff to garner how the operators used the current interfaces and procedures to perform tasks impacted by the upgrade. The data logger presented individual tasks listed in the SEGs per scenario, allowing the human factors engineer to collect observational notes, such as unsolicited comments and observed observational difficulties, while the logger timestamped comments.

An SME review worksheet for observation was also prepared by operations experts. The SME review worksheet allowed for the analysis of crew performance across monitoring, interpretation, strategy, actions, teamwork, and control and verification (Figure 7). The data recorded on these sheets was intended to help focus the post-scenario discussions, if warranted by the SME.

Subject Matter Expert (SME) Scenario Review and Observation

Monitoring refers to how the control room operators gather plant process information. The assessment of monitoring includes what process information the operators attend to, redundancy and diversification of the information obtained.	**Interpretation** refers to how the control room operators interpret the plant status and its progression. The assessment of interpretation includes the understanding of specific events, performance episodes, and the "big picture".	**Strategy** refers to how the control room operators establish main goals and a plan to reach these goals. The strategy assessment looks at how the control room operators understand the strategies provided by the standard operating procedures, and to what extent the operators are capable of adjusting and adapting these strategies when needed.	**Actions** concern the manipulation of systems and components. The focus is on key actions for controlling the plant process.	**Teamwork** concerns the interaction between team members. The evaluation focuses on leadership initiatives to perform consultations and distribute the work; involvement of team members; communication; backup behaviour and team climate.	**Control and Verification** refer to the team's critical thinking about their own work: the correspondence between the situation and the strategy chosen (Le Bot, 2010); the need to adapt plans to the situation; verification of plant process responses; and supervision of the progress towards established goals.
Real-Time Ratings					
1–2–3–4–5–6 NOT ACCEPTABLE ACCEPTABLE **Rating:** **Comments:**	1–2–3–4–5–6 NOT ACCEPTABLE ACCEPTABLE **Rating:** **Comments:**	1–2–3–4–5–6 NOT ACCEPTABLE ACCEPTABLE **Rating:** **Comments:**	1–2–3–4–5–6 NOT ACCEPTABLE ACCEPTABLE **Rating:** **Comments:**	1–2–3–4–5–6 NOT ACCEPTABLE ACCEPTABLE **Rating:** **Comments:**	1–2–3–4–5–6 NOT ACCEPTABLE ACCEPTABLE **Rating:** **Comments:**

Overall Rating Scale Key:

1	2	3	4	5	6
Strongly Not acceptable	Not Acceptable	Acceptability disputable, but probably not acceptable	Acceptability disputable, but probably acceptable	Acceptable	Strongly Acceptable
Requires follow-on discussion to identify possible contributors.				*No follow-on necessary.*	
Rating: **Comments:**				**Rating:**	

Figure 7. SME observation guide for the FRA & FA Workshop.

4.1.4.2 Scenario Execution, Surveys, and Discussions

4.1.4.2.1 Perform Scenario Observations

During the observations, the simulator was sometimes stopped at steps in the procedure where functions were added, eliminated, or changed due to the modernization effort and/or allocated differently than at present. The operators and others in attendance were asked to discuss these possible changes from existing practices. Normally, this information and these questions were asked during the scenario debriefs. Human factors staff used the data logger, SME scenario review worksheet, and general notes to collect observations. Figure 8 below illustrates two human factors staff members collecting notes during the scenario observations. Each staff member had a different role in observing performance. Here in Figure 8, one observer focused on overall crew performance while the other focused on specific actions taken by the CRS, using a data logger, which timestamped specific actions performed. The division of responsibility ensured completeness and accurate data collection throughout each scenario.

Figure 8. Human factors engineers collecting data scenario observations for the FRA & FA Workshop

4.1.4.2.2 Administer Electronic Surveys

After scenario completion, human factors staff assisted operators with accessing the electronic Microsoft Forms surveys of the National Aeronautics and Space Administration (NASA) – Task Load Index (TLX), Situation Awareness Rating Technique (SART), and Brief-Nuclear Usability Measure (B-NUM as described in INL/CON-18-45444 [32]). These surveys provided a baseline assessment of self-reported workload and situation awareness and were administered as an electronic packet sent to the operators' email address. The NASA-TLX collected self-reported workload data. Operators were instructed to answer these questions as quickly and accurately as possible after completing each scenario.

4.1.4.2.2.1 NASA-TLX

The NASA-TLX (Figure 9) is an industry-accepted tool for measuring and evaluating workload, as described in NUREG/CR-7190, "Workload, Situational Awareness, and Teamwork" [33]. The NASA TLX is a post-scenario rating method to assess workload, comprising six different dimensions: mental demand, physical demand, temporal demand, performance, effort, and frustration. Each dimension (i.e., question) typically uses a standardized scale (e.g., 1 = low; 10 = high) where higher values denote a greater workload. A common practice is to remove the 15 pairwise comparisons and only use the rating scales for each workload dimension. Workload can be evaluated by each dimension and holistically from aggregating the individual scales.

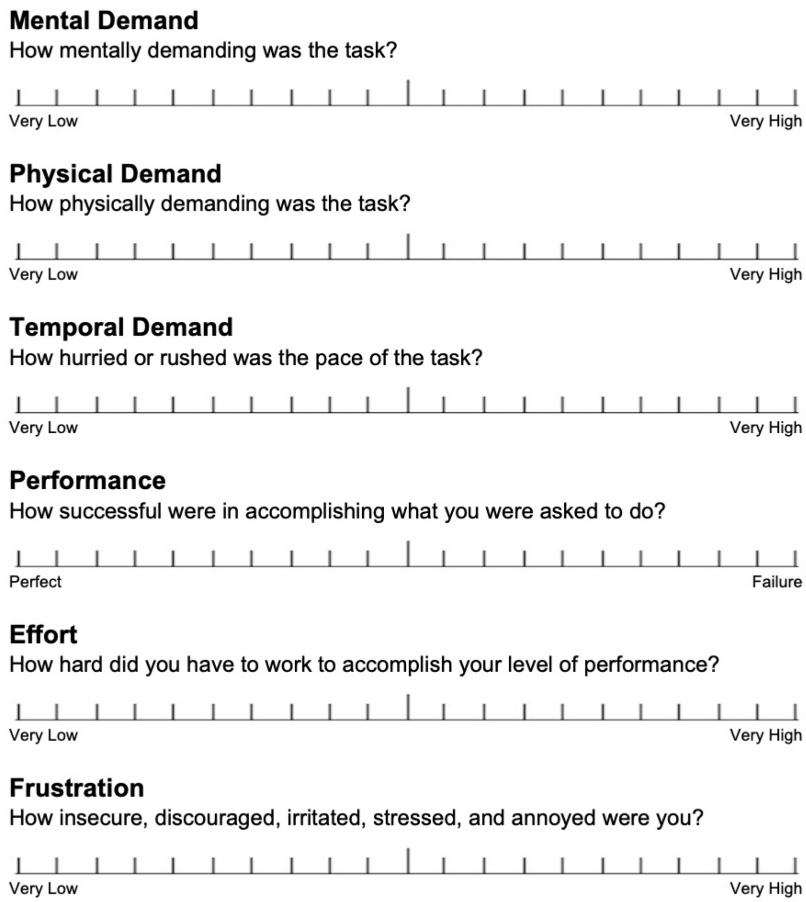


Figure 9. NASA-TLX standardized survey instrument.

4.1.4.2.2.2 SART

The SART is a self-report standardized survey that measures perceived situation awareness (Figure 10) with a series of standardized questions using a seven-point rating scale (1 = low; 7 = high). These questions aggregate into three primary dimensions: Understanding, Demand, and Supply. Understanding refers to one's general understanding of the situations and is a combination of information quantity, information quality, and familiarity. Demand refers to one's attentional demands (i.e., like workload) and is a combination of task complexity, variability, and situation instability. Finally, Supply refers to one's attentional supply and is a combination of attentional arousal, focusing of attention, spare mental capacity, and mental concentration. The relationship of these three dimensions score a common situation awareness measure from the following equation: Situation Awareness = Understanding – (Demand – Supply). A composite situation awareness score is derived from SART where a greater value denotes greater situation awareness. SART is also cited in NUREG/CR-7190 [33], but is cautioned as a primary source to measure situation awareness; hence, this workshop used SART in combination with naturalistic observation and semi-structured questions described in the post-scenario discussion.

SART

Instability of Situation
How changeable is the situation? Is the situation highly unstable and likely to change suddenly (High) or is it very stable and straightforward (Low)?

1 = Low	2	3	4	5	6	7 = High

Complexity of Situation
How complicated is the situation? Is it complex with many interrelated components (High) or is it simple and straightforward (Low)?

1 = Low	2	3	4	5	6	7 = High

Variability of Situation
How many variables are changing within the situation? Are there a large number of factors varying (High) or are there very few variables changing (Low)?

1 = Low	2	3	4	5	6	7 = High

Arousal
How aroused are you by the situation? Are you alert and ready for activity (High) or do you have a low degree of alertness (Low)?

1 = Low	2	3	4	5	6	7 = High

Concentration of Attention
How much are you concentrating on the situation? Are you concentrating on many aspects of the situation (High) or are you focused on only one (Low)?

1 = Low	2	3	4	5	6	7 = High

Division of Attention
How much is your attention divided by the situation? Are you concentrating on many aspects of the situation (High) or focused on only one (Low)?

1 = Low	2	3	4	5	6	7 = High

Spare Mental Capacity
How much mental capacity do you have to spare in the situation? Do you have sufficient to attend to many variables (High) or nothing to spare at all (Low)?

1 = Low	2	3	4	5	6	7 = High

Information Quantity
How much information have you gained about the situation? Have you received and understood a great deal of knowledge (High) or very little (Low)?

1 = Low	2	3	4	5	6	7 = High

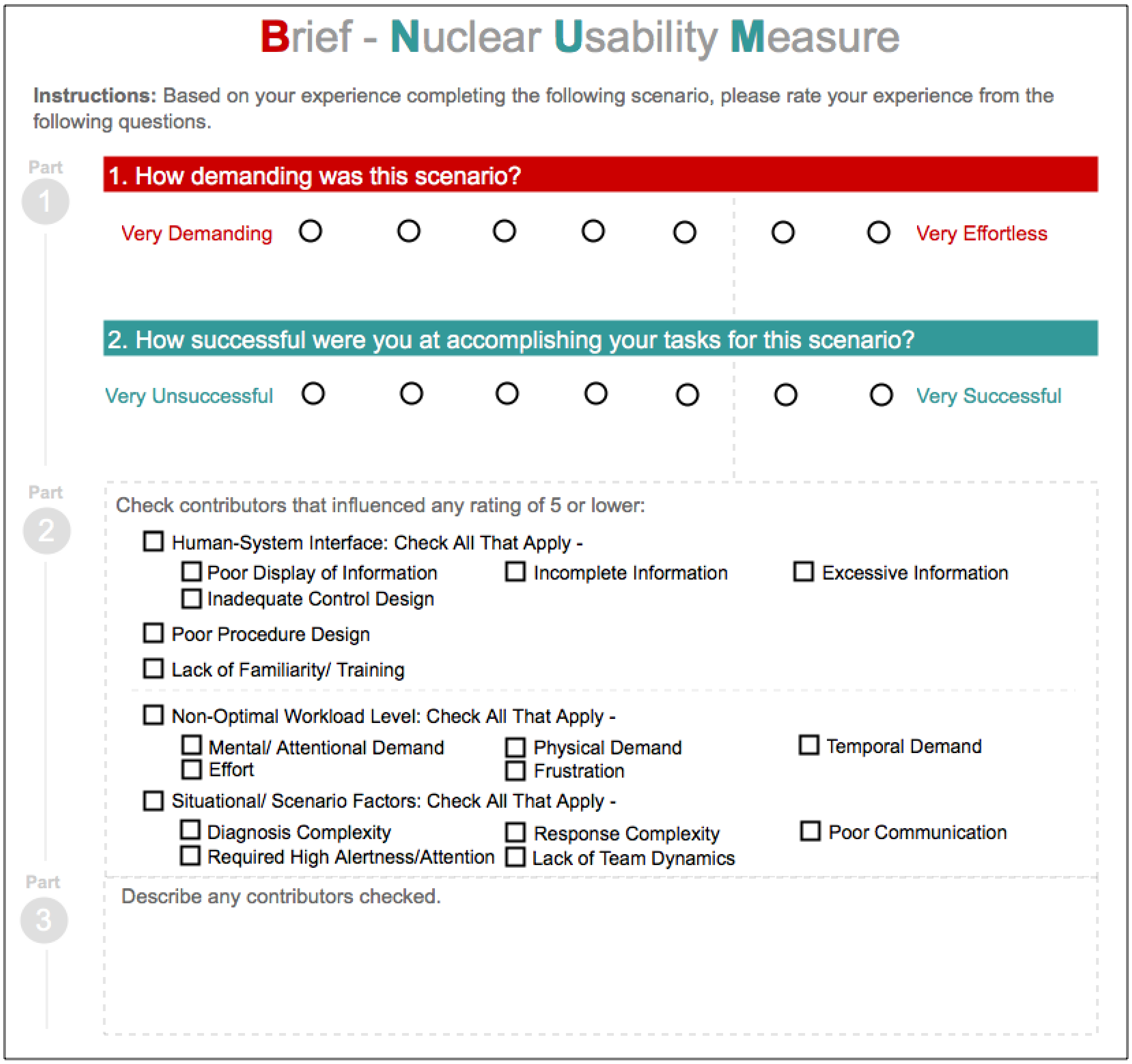
Familiarity with Situation
How familiar are you with the situation? Do you have a great deal of relevant experience (High) or is it a new situation (Low)?

1 = Low	2	3	4	5	6	7 = High

Figure 10. SART standardized survey instrument.

4.1.4.2.2.3 *Brief - Nuclear Usability Measure*

Finally, the electronic surveys included the Brief - Nuclear Usability Measure (B-NUM), a recently developed survey tool [32], see Figure 11 for an example. The B-NUM is an aggregated survey meant to measure self-reported workload and situation awareness based on two key questions. The tool was derived from NASA-TLX and SART but adds an additional quality of collecting diagnostic information on the responses. That is, the survey responder has the capability to check performance shaping factors (i.e., contributors) to low ratings for self-report workload and/or situation awareness. The responder can then describe the specific attributes of these contributors in more detail in an open text field. The advantage of using B-NUM in this sense is to collect early feedback on contributors to low situation awareness and/or high workload to better inform design.



Brief - Nuclear Usability Measure

Instructions: Based on your experience completing the following scenario, please rate your experience from the following questions.

Part 1

1. How demanding was this scenario?

Very Demanding ○ ○ ○ ○ ○ ○ ○ Very Effortless

2. How successful were you at accomplishing your tasks for this scenario?

Very Unsuccessful ○ ○ ○ ○ ○ ○ ○ Very Successful

Part 2

Check contributors that influenced any rating of 5 or lower:

- ☐ Human-System Interface: Check All That Apply -
  - ☐ Poor Display of Information
  - ☐ Incomplete Information
  - ☐ Excessive Information
  - ☐ Inadequate Control Design
- ☐ Poor Procedure Design
- ☐ Lack of Familiarity/ Training
- ☐ Non-Optimal Workload Level: Check All That Apply -
  - ☐ Mental/ Attentional Demand
  - ☐ Physical Demand
  - ☐ Temporal Demand
  - ☐ Effort
  - ☐ Frustration
- ☐ Situational/ Scenario Factors: Check All That Apply -
  - ☐ Diagnosis Complexity
  - ☐ Response Complexity
  - ☐ Poor Communication
  - ☐ Required High Alertness/Attention
  - ☐ Lack of Team Dynamics

Part 3

Describe any contributors checked.

Figure 11. B-NUM standardized survey instrument.

4.1.4.2.3 Perform Post-Scenario Discussion

After survey completion, human factors staff prepared to video record. There was a primary notetaker during the debrief for LGS and INL. LGS first performed a crew debrief following the scenario. A three-dimensional (3D) model, showing the modifications, was used to focus on the discussion. After the LGS debrief, human factors staff facilitated additional discussion, using the workflow in Figure 12 as a template. Additional questions were asked by others as needed, particularly with any observed difficulties.

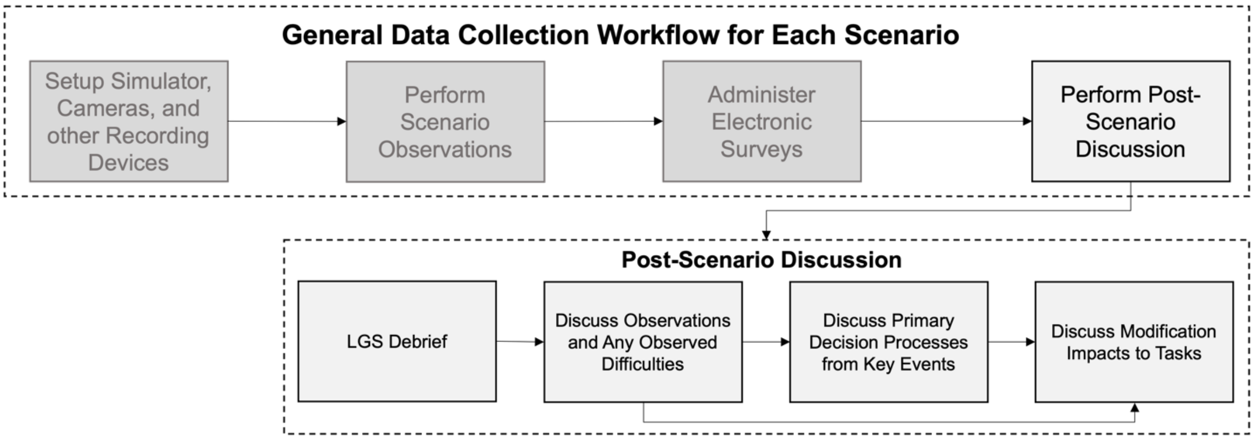


Figure 12. Post-scenario discussion workflow for FRA & FA Workshop.

4.1.4.2.3.1 LGS Debrief

LGS performed a debrief to initiate the post-scenario discussion. The crew members each discussed what primary tasks they performed, what went well, and where they had notable challenges. INL collected notes and contributed to this discussion.

4.1.4.2.3.2 Discuss Observations and Observed Difficulties

Any observed difficulties collected during the scenario that were covered in the LGS debrief were discussed next and reviewed within the context of contributors, including HSI design, procedure design, training, and/or simulator artifacts (Figure 13).

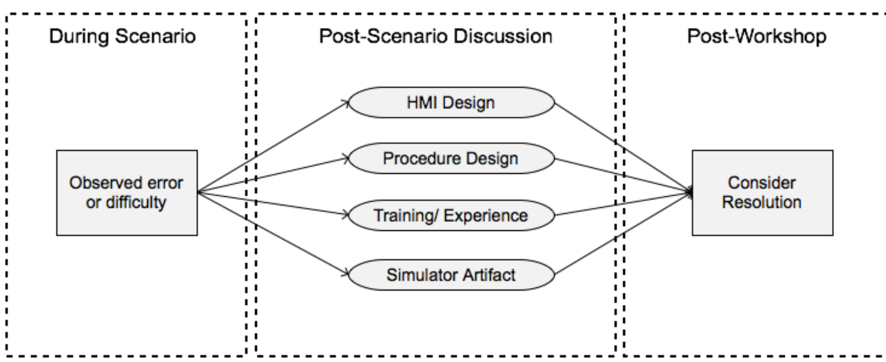


Figure 13. Contributors to observational difficulties.

If there are no observed difficulties, questions, such as the following, were administered by human factors staff members:

- Was there anything about the existing indications and controls that made this scenario difficult to perform?
- Were there difficulties accessing information to enable you to effectively monitor the plant, diagnose faults, and/or maintain situation awareness? How might this be improved?
- Were there difficulties taking control actions with the existing controls? Tedious actions? Difficult actions?
- Are there tasks that should be automated (e.g., tedious tasks, instances of multi-tasking, tasks required communication outside the MCR, etc.)? What tasks? Why?

4.1.4.2.3.3 Discuss Primary Decisions Processes from Key Events

For key events, there are identified areas of increased uncertainty where operators are provided incomplete information. Human factors staff asked questions, such as those listed below, during the discussion of the primary decision processes to understand the cognitive activities required to bring the plant to a safe state.

- What is the overall goal in this event?
- What alerting cues (e.g., alarms) did you use to identify that there was a change in plant state?
- What information did you seek to gain an understanding of the situation?
- What exactly were you looking for? A threshold or limit? A value? Etc.
- Where did you find this information?
- What plant process computer (PPC) displays were used (if any)?
- Were there any parameters being monitored throughout the course of diagnosing the event?
- How did you integrate this information to make sense of it in understanding the plant state?
- Were you able to readily identify a response from the information, or did the event require you to go through a series of diagnosis activities?
- Were there other possible plant states that you had to differentiate from given the information you collected? If so, how did you do this?
- What indications/ controls were used? Procedures?
- What sort of crew coordination was required?
- Were there other events or plant conditions that you had to contend with?
- How did you prioritize? What goals were considered when prioritizing?
- Were there additional ways to reach the same diagnosis of events?
- If yes, what caused you to select your method of diagnosis?
- Is the information you used more accessible, easier to understand, less manual calculations, etc.?
- What course of action was selected? What procedures were used?

4.1.4.2.3.4 Discuss Modifications Impacts

A conceptual 3D model was produced by INL based on initial design concepts communicated by Constellation, see Figure 14.

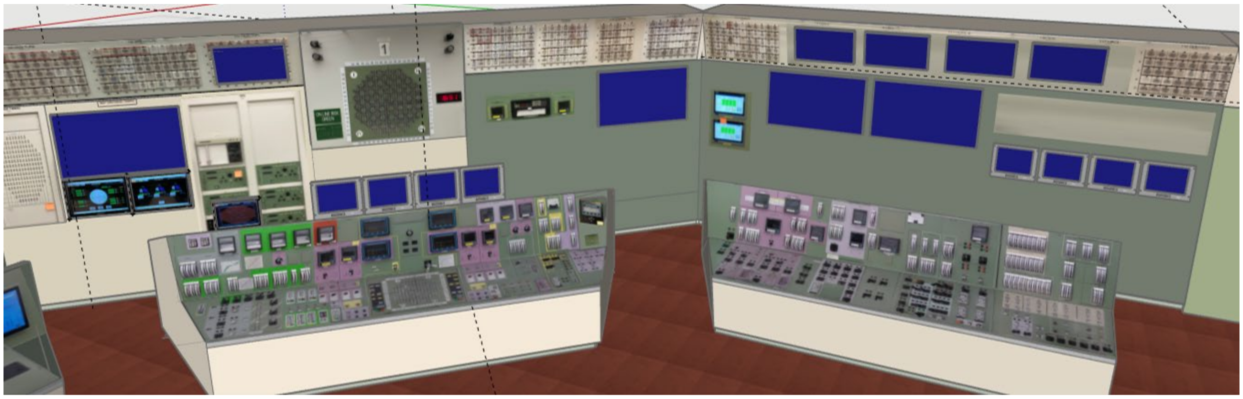


Figure 14. 3D model of initial Limerick Unit 1 MCR upgrade layout.

Based on their experience when executing the FRA & FA scenarios, human factors staff asked the questions in the following subsections to Constellation workshop participants.

General and Task/ Information Requirements

- Based on the scenario you've performed, what are your impressions with the proposed modifications in terms of how you believe it may support or not support the tasks you performed here?
- How might you see the large screen overview displays be used?
- From the scenario, what specific displays would be likely used for monitoring?
- Are there specific parameters or information you would want to see on these overviews?
- Are there specific PPC displays that were used that you wished were located on these?
- What information from these displays is most critical?
- What is the preferred format of this information?

Task/ Information Requirements and Anthropometrics

- From a CRS point of view, do you have any concerns with the viewability of information?
- Do the PPS displays occlude the Ovation displays for monitoring?
- Based on the task flow from the operators during this scenario, would there be any concerns or distractions from using the overview displays?

Task Information Requirements and Anthropometrics

- From an RO point of view, do you have any concerns with the viewability of information?

Automation

LTR-AMER-MKG-21-656, Rev. 2 [27] was used as needed for automation details.

- How might the automated operator aids from LTR-AMER-MKG-21-656 [27] support you with this scenario?
- What are the specific benefits of these aids in this scenario?
- What specific human error trap(s) does it mitigate?

- What information would be important for you to understand whether [*particular aid*] is operating correctly?
  - Logic drill-down?
  - Mimic overview with embedded process data?
  - Both? Other?
- Are there specific concerns you have with the proposed automation in this scenario?
- Are there any other enhancements (e.g., additional features and functions) you can think of?

4.1.4.2.4 Final Discussion

The final wrap-up discussion was facilitated and recorded by INL to:

- Verify information collected during the walkthroughs is accurate and complete
- Collect any additional impacts to the physical layout identified from the scenarios
- Identify and confirm representative displays (e.g., using PPC) for the common scenarios are identified to prepare for the TAs workshop
- Confirm a set of representative scenarios for the TAs workshop, including training guides, procedures, and representative PPC displays currently used for these scenarios
- Identify action items
- Open discussion (i.e., items not previously covered before workshop close out).

4.1.5 Step 4—Documentation and Use of Results

A summary of FRA & FA workshop results are documented in Section 4.2 and Appendix A of this report. These results served as inputs into the TA workshop described in Section 5.1.1.

4.2 Functional Requirements Analysis and Function Allocations Results Summary

4.2.1 Key Findings

Key findings from the FRA & FA workshop are:

1. The plant is highly dynamic and operator actions often occur in parallel (particularly during casualty events).
2. In many situations, operators can achieve successful plant safety/operational outcomes in more than one way when following the same set of procedures.
3. Operators leverage the existing “flat topology” of indications and controls to enable the capability identified by Findings 1 and 2.
4. The new HSIs provided by the project need to maintain/enhance the existing MCR/plant concept of operations through creating HSIs that support the capabilities described Findings 1–3.
5. Many of the existing controls and indications are dispersed (i.e., across the MCR and sometimes in the field), which inhibits optimal MCR personnel performance by requiring operators and supervisors to “ping-pong” across the MCR to access appropriate indications and controls to diagnose issues and take proper control actions.
6. There are highly manual tasks (e.g., controlling pressure via SRVs) where operators are required to remain in a particular location at the control board, which inhibits optimal operator and watchteam performance.

7. There is little rate of change trending available related to the existing fixed analog displays. Plant data digitization by the upgrade needs to provide the rate of change/trending to improve the "mental model" of the plant to enable improved performance.

   More detailed FRA & FA results can be found in Appendix A – FRA & FA detailed results.

4.2.2 Workshop-Driven Main Control Room Concept of Operations Modification

As observed during the FRA & FA workshop, the existing MCR concept of operation for Limerick for casualty response is based on the watchteam having access to an HSI characterized as a "flat topology." Operators have direct access to all system/component-level indications and controls through the panel and benchboard HSIs.

Operator actions, as observed through FRA & FA workshop scenario execution, are accomplished by dynamic "parallel processing" of procedure paths. This parallel processing involves the execution of high-level procedures (T-100s) by the CRS. Many events call for the simultaneous execution of Reactor Pressure Vessel pressure and level control (T-101), primary containment control (T-102), and secondary containment control (T-103). The T-100 procedures also call out supplementary procedures (T-200s). The CRS will give orders to the RO, PRO, or EOs to execute the T-200 procedures (in whole or part) and report back when complete. The RO, PRO, or EOs can implement the T-200s as directed by the CRS in parallel to achieve desired results.

There are, in most cases, several different paths that can be followed to achieve "acceptable" end-state results. Many of these paths include the watchteam disabling the automatic actuation of systems and components. The path chosen in many cases depends on expert judgement and the consensus of the watchteam to achieve a "best" end state in terms of safety (paramount), plant impact, and investment protection.

The communication method employed in the Limerick MCR is also different when compared to the PWR. In casualty situations, an RO will sometimes announce actions that he is going to take to the watchteam/CRS and then execute them unless the watchteam/CRS intervenes. The CRS will also give orders to the RO, PRO, or EO to execute whole procedures (T-200s) and report back when complete. INL HFE researcher experience prior to participating in this upgrade has been almost exclusively focused on PWR technology (see Section 4.1.1.4). Generically, the concept of operations for a PWR MCR as understood by INL HFE researchers is that it is much more linear than observed at the Limerick BWR. As INL HFE researchers became more familiar with Limerick's BWR design through observing operator scenario performance, it became apparent that the observed "parallel processing" operating model was well suited to the plant design. While the procedure parallel processing and communication methods were different from that previously observed by INL researchers in PWR MCR operation, they were observed to be formal and well understood by watchteam members and enabled a level of performance that was at least equally acceptable when compared to INL researcher observations of PWR MCR performance.

Since MCR operator training is based on this concept of operations, Limerick Operations determined and INL researchers agreed that applying a PWR hierarchical HSI display structure at Limerick, as originally envisioned as described in Section 4.1.1.4, would be unwise. Such an effort would either be a "force fit" to support the current MCR concept of operation for casualty response or require a significant change to the MCR concept of operations. Either would likely require significant operator retraining. It would also potentially negatively impact both the accuracy and speed of casualty response. Consequently, the new HSIs installed as part of the project needs to support/augment the existing MCR HSI "flat topology" and the existing MCR concept of operations for casualty response.

This decision to change initial direction with regard to HSIs design as described above is consistent with the iterative nature of establishing an MCR concept of operation, shown in Figure 15 below as described in Section 6.3 of INL/LTD-21-64899 [2]. Observing the existing concept of operations, shown at the right of Figure 15, resulted in a modification of the conceptual design direction for MCR HSIs, shown at the left in the figure.

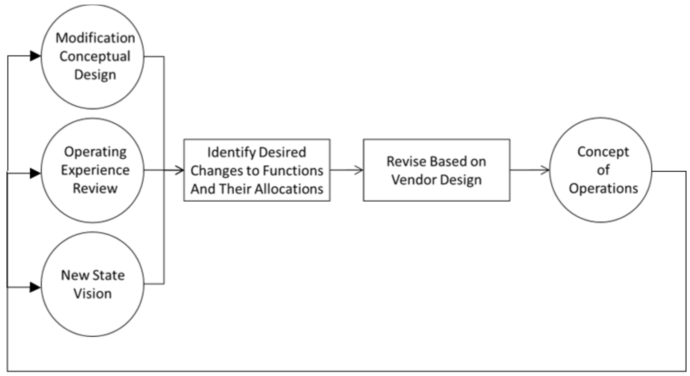


Figure 15. Development of a Concept of Operations.

Challenges to maintaining the MCR HSI "flat topology" above as part of this upgrade include:

- The "artificial segmentation" (from an operator point of view) of the HSIs based upon the use of divisionalized PPS VDUs and separate digital platforms (PPS and DCS)
- The project requirement that operators be able to achieve a "safe state" during major plant casualties using only the safety systems and with a concurrent loss of the DCS.

5 TASK ANALYSIS

5.1 Method

TA is a collection of different data collection, visualization, and analysis techniques that all have a common purpose. Within the context of nuclear power plant modernization, TA is the analysis of functions assigned to plant personnel in order to satisfy the requirements for successful performance. The actions personnel must do to accomplish functions assigned to them are called "tasks." Generally, "task" refers to a group of activities with a common purpose. The fundamental basis of TA is a decomposition of tasks into the constituent activities to accomplish a goal. The degree of decomposition varies depending on the purpose of the TA. Figure 16 illustrates the decomposition of tasks as demonstrated by TA.

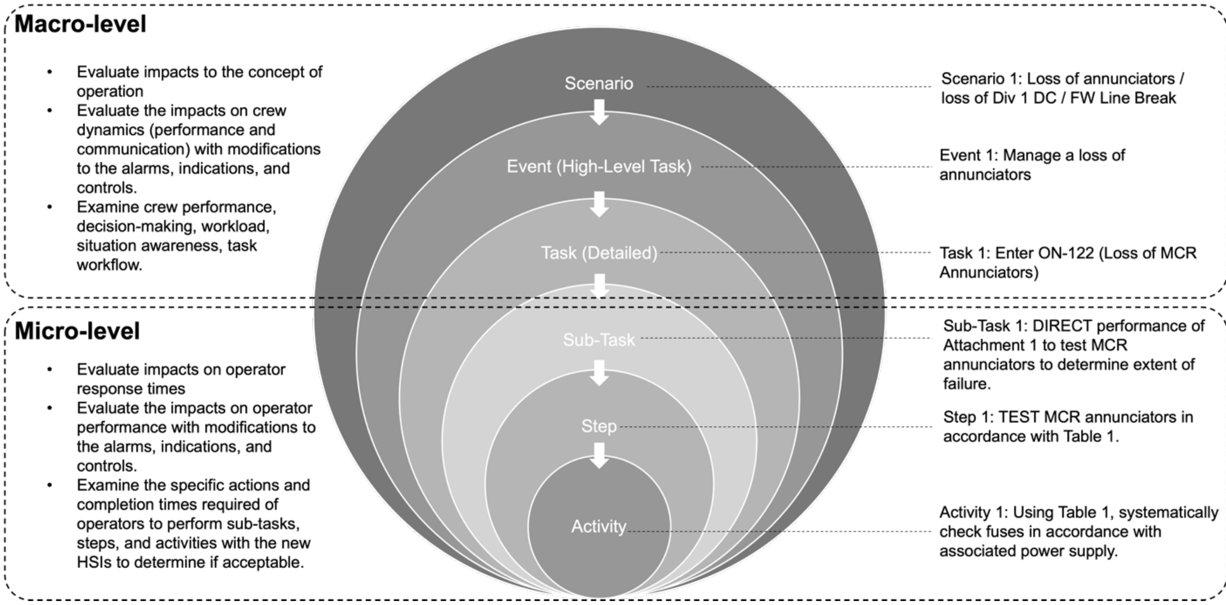


Figure 16. Decomposition of tasks for performing TA.

As seen in Figure 16, a top-down approach is taken by developing scenarios that comprise one or more events (i.e., high-level tasks), which are logically grouped in terms of accomplishing a goal. The individual tasks are contained within a scenario and event to accomplish these goals. The benefit of performing TA in this way is that tasks can be evaluated naturalistically. The influence of other tasks being performed in succession or in parallel can be properly analyzed in this manner. Further, by analyzing tasks from scenarios and events, the human factors engineer can understand how modifications to the HSIs needed to perform these tasks can influence "macrolevel" HFE considerations, such as how the specific modifications impact crew performance and decision-making, situation awareness, workload, and overall task workflow. Put differently, these macrolevel HFE considerations are important when understanding how the modifications impact the concept of operations.

As the design matures and specific HSIs and design features are identified, the TA can be iterated upon and the scenarios, high-level tasks, and tasks can be further decomposed and analyzed to understand the impacts to "micro-level" HFE considerations that are concerned with the interaction with specific design features from the HSIs. It is here that the TA can examine the time required to perform specific tasks, subtasks, steps, and activities tied to important HAs with the defined HSIs via operational sequence analysis (OSAs) and operational sequence diagrams (OSDs), as described in NUREG-0800, Chapter 18, Attachment A, "Guidance for Evaluating Credited Manual Operator Actions [34], NUREG-1764 [5], and NUREG-1852, "Demonstrating the Feasibility and Reliability of Operator Manual Actions in Response to Fire" [35].

The approach taken here for TA was to begin with macrolevel considerations to define the impacts to the concept of operations and resulting impacts to the alarms, indications, decision processes, control actions, communication, workload, and interaction of tasks in addressing specific events. While some micro-level TA methods, such as cognitive modeling, have been used to analyze interactions with the new HSIs, it was expected that the TA will be iterated upon by the HFE team in later activities as described in the HFE Program Plan [1], including the static and dynamic workshops in which the HSIs will be further defined and the application of OSAs and OSDs can be appropriately performed. Moreover, the identification of any new tasks credited in the accident analysis can be better identified at this time, at which point TA can address these new tasks at a macro- and micro-level, respectively. It is assumed that subsequent HFE activities described in the HFE Program Plan [1] will further enable TA iteration and more detailed micro-level analyses will be performed to further support detailed HSI design, procedure design, training, and V&V (e.g., Task Support Verification).

Collectively, the requirements developed in TA are a primary consideration in designing the HSIs, procedures, and training provided to plant personnel. TA evaluates personnel tasks in sufficient detail to identify the requirements for task performance, including the alarms, information, controls, procedures, and training needed to perform the tasks. TA results hence have many uses in subsequent analyses, including staffing, error analysis, HSI and procedure design, training, and V&V. The methodology followed here for performing TA is based on an EPRI HFE guidelines report [6]. The major activities are shown in Figure 17. The primary activities shown in this methodology are summarized next.

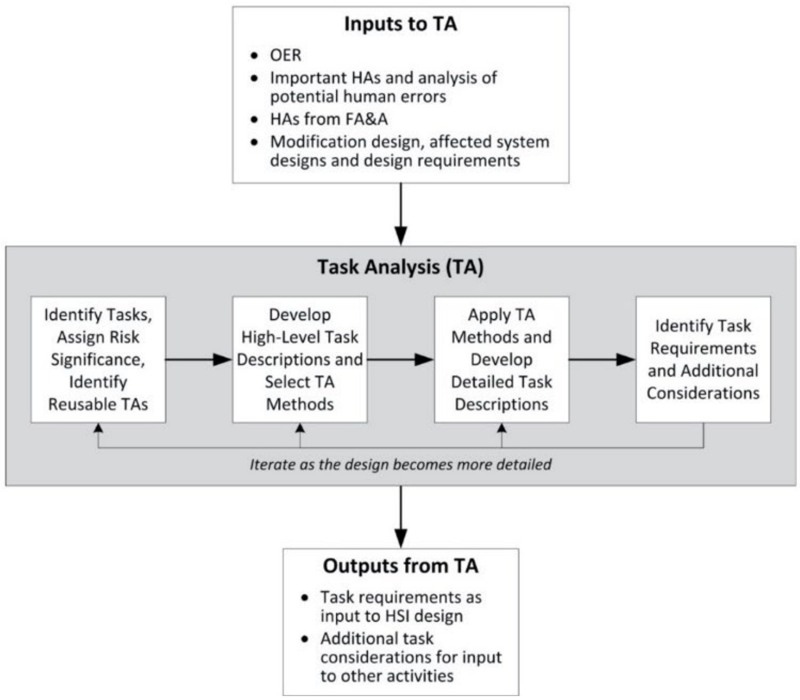


Figure 17. TA overview.

5.1.1 Inputs to Task Analysis

5.1.1.1 Task Analysis Inputs from Earlier Human Factors Engineering and Other Activities

Necessary TA inputs flowing from earlier HFE Program implementation efforts as well as those identified from I&C system analyses included the following:

- The modification scope (Section 4.1.1.1)
- OER results (Section 4.1.1.3)
- FRA & FA results (Section 4.2.1)
- The MCR concept of operations (Sections 4.1.1.4, and 4.2.2)
- HAs credited in the D3 analysis performed to address potential PPS common cause failures [31] as well as the HAs credited in the LGS UFSAR [30] and PRA [41] for accident mitigation.

These inputs collectively provided information about impacted tasks, which of these tasks were problematic, and where there is significant opportunity for improvements with the new HSIs.

5.1.1.2 Additional Inputs Created to Support the Task Analysis

5.1.1.2.1 Three-Dimensional Main Control Room Modeling

3D MCR models supported the FRA & FA, as described in Section 4.1.4.2.3.4, and the TA. That is, when performing knowledge elicitation activities, the models served as a visual reference to the MCR Unit 1 to enrich the discussion, identify human error traps, and drive development of the optimal placement of HSIs for the upgrade.

Refinements to the 3D model shown in Figure 18 were performed based on LGS operations and engineering input during the FRA & FA workshop and in the lead up to the TA Workshop. The resultant 3D model arrangement used as an input to the TA Workshop is presented in Figure 18 below.

Figure 18. 3D model showing pre-TA modifications and 5th percentile female reach envelope.

Anthropometrically correct mannequins were added to the 3D environment, as shown in Figure 18, to evaluate VDU and control placement to ensure adequate sightlines, reach, and overall placement, following guidance from NUREG-0700, "Human-System Interface Design Review Guidelines" [36].

The 3D model was used (and will continue to be used in the future) to support analysis from NUREG- 0700 Revision 2 Chapter 1 (Information Display) and Chapter 11 (Workstation Design) by identifying ergonomic and anthropometric data (see Table 3).

Table 3. Applicable HFE design guidance from NUREG-0700 [36].

Criteria	Guideline	Description
Functional Reach	11.1.1-2 (Control Height)	The highest control on a stand-up console should be within the highest reach of the 5th percentile female without stretching or using a stool or ladder, while the lowest controls should be within the lowest reach of the 95th percentile male without bending or stooping.
Viewing Angle	11.1.1-6 (Display Height and Orientation)	All displays, including alarm indicators, should be within the upper limit of the visual field (75 degrees above the horizontal line of sight) of the 5th percentile female and should be mounted so that the interior angle between the line of sight and the display face is 45 degrees or greater.
	11.1.1-7 (Location of Frequently Monitored Displays)	Displays that require frequent or continuous monitoring, or that may display important (e.g., alarm) information, should be located not more than 35 degrees to the left or right of the

Criteria	Guideline	Description
		user's straight-ahead line of sight (LOS) and not more than 35 degrees above and 25 degrees below the user's horizontal LOS, measured from the normal workstation.
Legibility	1.3.1-4 (Character Size for Text Readability)	The height of characters in displayed text or labels should be at least 16 minutes of arc and the maximum character height should be 24 minutes of arc.

Data from functional reach, viewing angles, legibility, HSI designs, and workplace design layouts are identified when using 3D 5th percentile female and 95th percentile male mannequins in the 3D models to measure functional reach of controls or viewing angles of HSI screens. The results were used to inform engineering and operations on the placement of equipment and controls.

5.1.1.2.2 Use of the Human-Systems Simulation Laboratory

In order to provide the most realistic environment possible to perform the TA, the project decided to leverage the INL Human-Systems Simulation Laboratory (HSSL). The HSSL is capable of emulating MCR functionality through a configurable set of digital bays, each of which presents three 55-in. touch screen, flat-panel VDUs. These can be configured in such a way as to approximate existing MCR layouts, as well as to provide a "canvas" to present conceptual MCR modifications.

The 3D model shown in Figure 18 was also used as a guide to establish the HSI layout in the INL HSSL. The objective of this effort was to provide a realistic approximation of the location and functionality of the new VDUs in the HSSL for the TA Workshop to obtain operator feedback on the latest notional MCR layout. The actual 3D model from Figure 18 was also presented on a large monitor in the HSSL during the TA scenario walkthrough analyses to communicate concepts and placements of controls and HSI screens for operations and engineering reviews. The 3D model enabled quick reviews for measuring maneuverability in the MCR and other workplace designs needing to be reviewed by operations and engineering at the time of the workshop.

5.1.1.2.3 Prototype Displays and Navigation Strategy

Prototype HSI displays for both the PPS (Common Q) and Ovation (DCS) were rendered by INL along with a notional navigation strategy. These displays and the navigation strategy were developed through a collaboration between personnel from LGS (engineering, operations, and training personnel), Westinghouse, and INL to reflect the latest HSI design concepts. Based upon the revision of the concept of operations, as captured in Section 4.2.2, the conceptual PPS and DCS displays were formulated to maximize the use of available VDU space provided by both systems and to support, augment, and improve on the HSI "flat topology" currently used in the Limerick MCR.

The result of these efforts was then loaded on the HSSL. The HSSL provides operators with the ability to view the notional displays and exercise the navigation strategies on representative VDU's. For the workshop, a mix of computer workstations, and the HSSL bays described in Section 5.1.1.2.2 were used to represent the new VDUs. The layout of the upgrade VDUs from Figure 18 and the prototype display functionality presented on them was reflected in the HSSL configuration for the TA workshop and is shown in Figure 19 below.

Figure 19. Configuration of HSSL for the TA Workshop.

The prototype displays developed and used in the TA were developed in the C# programming language using the Windows Presentation Foundation (WPF), a subset of Microsoft's.NET framework, which uses the Extensible Application Markup Language. WPF comes equipped with a broad set of development features, resources, controls, graphics, layout, data binding, and other characteristics that can lend themselves well to the quick prototyping required for this workshop. The simulator prototypes were built to interface with Microsoft technologies, such as access databases. This was another factor in choosing WPF as a framework for building the prototypes used in this workshop.

An executable program was compiled for each prototype display used in the workshop and placed in a directory of its same name along with the required dynamic link libraries for executing that program. These were placed on the same drive the simulator was mapped to so that they could be run from any bay or computer on the local network.

INL also was able to import and run the operating simulator model from the LGS training simulator on the HSSL. The objective of this effort is to provide interactive display prototyping capability during initial HSI development and subsequent refinement prior to rendering the displays in Common Q (PPS) and Ovation (DCS).

Ideally, having fully dynamic conceptual HSIs for the TA workshop would have been preferred (but is it not required). Due to the schedule of executing the workshop and the large quantity of variables existing in the simulator, only a small number of variables for Limerick model could be mapped to their respective widgets on the prototypes displays.

Overviews displays one through three, and part of four (as captured in Appendix D), were built to be dynamic displays, pulling live values from the simulator, and responding to those state changes in real time. The top-most, horizontal indicators displayed live values of variables that plant operators find useful to always monitor. Other useful live values were displayed throughout the overviews as numerical display readouts. Pump and valve widgets were also displayed in these overviews and were built to dynamically change color according to their status. For instance, when a valve has a value of 0 in the simulator, representing a fully closed state, it displayed as fully green. Similarly, when the associated valve has a value of 1 in the simulator, it displayed as fully red (open state) in the simulator. As a valve transitioned from closed to open (i.e., 0 to 1) in the simulator, the corresponding valve in the prototype also transitioned incrementally from green to red in real time to reflect this change. The same is true for valves transitioning from open to closed (i.e., red to green or 1 to 0). For instance, if a valve started in an open position (a value of 1) and was transitioning to a closed position (a value of 0), while in a position between.05 and.95, one part of the valve would be red while the other part would be green.

System-level PPS display variables were not mapped. Conceptual navigation features were presented and exercised discussed during scenario walkthroughs.

Since schedule and logistics issues prevented having fully dynamic displays for the TA workshop, the design team was able to leverage the HSSL’s flexibility to provide an alternative that went beyond using just the limited capability of the notional digital displays created for the workshop as described above. Sufficient real estate existed on the HSSL VDU bays to present both the current and fully functional HSIs from the Limerick simulator in digital form while at the same time presenting the DCS overview displays created for the workshop. This allowed the operator subjects participating in the workshop to cross reference data produced from the simulator and presented on the current HSIs to the way this data is being packaged on the DCS overview displays. This is shown on Bays 3–6 in the background of Figure 19. The overview displays described above are shown on the top screens of Bays 3–6.

Appendix D provides copies of the prototype displays used in the TA workshop and also provides descriptions of the navigation techniques provided in the HSSL.

5.1.2 Methodology and Procedure

5.1.2.1 Initial Human Factors Engineering Project Screening and Assignment of Project Risk Significance

The SR I&C upgrade project was initially screened to determine the extent of potential HFE impacts. Changes considered in project screening included those that impacted operator HSIs. Changes that did not modify HSIs but could have other potential impact on operator tasks were also considered. The project screening process followed was based on guidance given in NUREG-0800, Chapter 18, Sections II.B and II.C [34] and EPRI HFE guidance [6]. This process is described in the HFE Program Plan [2] in Section 6.6.1. Figure 20, which depicts this process from the HFE Program Plan [2], is repeated below for convenience.

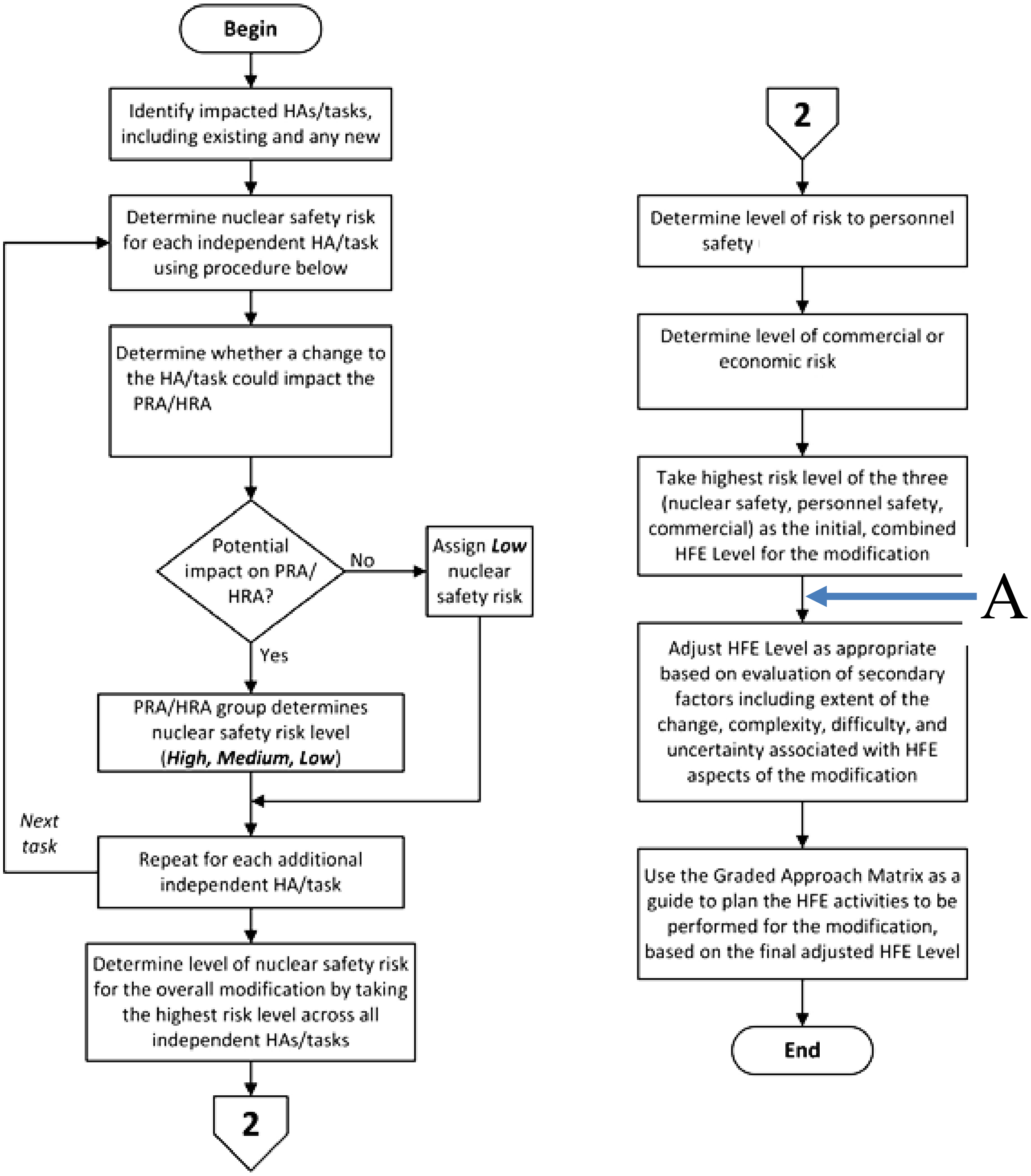


Figure 20. Process for determining HFE level of activity through project screening

This process first determined if any important HAs related to nuclear safety (i.e., identified from the LGS UFSAR [30], D3 analysis [31], and PRA [41]) may be impacted by the modification as an input to the initial screening. Initial screening also considered personnel safety and the risk to commercial operation. This executes the process shown in Figure 20 (up to Point "A").

Figure 21 shows the results of this initial project screening and leverages an analysis tool developed as part of the EPRI guidance [6] for this purpose. The results indicated an initial screening grade of Level 1 (i.e., high potential nuclear safety risk and economic risk; there is no anticipated personnel safety risk).

HFE GRADED APPROACH CHECKLIST (Based upon EPRI 3002004310 Form F-02)

Assessment of Potential Risk to Plant Safety and Economic Operation

	Assessment (Mark with X) Yes	No		Discussion
1.1 Potential Risk to Nuclear Safety				
1.1.1 Could the modification impact any human actions (HAs) credited in the plant safety analysis as described in the SAR? If Yes, assign a High nuclear safety risk level and list the HAs that could be impacted.	[ ](C)	[ ](C)		[ ](C)
1.1.2 Could the modification impact any HAs credited in a diversity & defense-in-depth (D3) analysis? If Yes, assign a High nuclear safety risk level and list the HAs that could be impacted.	[ ](C)	[ ](C)		[ ](C)
1.1.3 Could the modification impact any HAs that are risk-important based on the PRA/HRA? A High nuclear safety risk level is assigned. List the HAs that could be impacted.	[ ](C)	[ ](C)		[ ](C)
1.1.4 Does the modification make significant changes to any operator human-system interface (HSI) or permanently-installed maintenance HSI for a system or equipment that is safety-related, or is considered risk-important based on the PRA? At least one of 1.1.1 - 1.1.4 above was YES, resulting in assignment of a High level of potential nuclear safety risk. List the impacted HSIs and proceed to 1.1.7 below	[ ](C)	[ ](C)		[ ](C)
1.1.6 Could the modification impact any HAs that are potentially risk-important based on the PRA/HRA, depending on the changes that are made? The answer is YES: Work with the PRA/HRA group to determine the appropriate level of nuclear safety risk based on the nature of the changes and their potential impact on the identified HAs. List the affected HAs.	[ ](C)	[ ](C)		See 1.1.3 above.
	High	**Medium**	**Low**	
1.1.7 The assigned level of nuclear safety risk based on 1.1.1-1.1.6 above:	[ ](C)	[ ](C)	[ ](C)	
1.2 Potential Risk to Economic Operation	**High**	**Medium**	**Low**	
1.2.1 Determine the potential risk to plant operation considering the possibility that a human error in performing affected human actions or tasks, or in working with the impacted HSIs, could result in: • A plant trip • Prolonging an outage • A power reduction or damage to plant equipment • One or more Licensee Event Reports (LERs) • One or more negative INPO findings • Negative impact on Key Performance Indicators (KPIs)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
1.3 Initial HFE Level – higher of the two risk levels assigned to nuclear safety (1.1) and plant economic operation (1.2):	[ ](C)	[ ](C)	[ ](C)	

Figure 21. Initial Limerick SR I&C Upgrade Project HFE Screening.

Next, secondary factors were assessed based on EPRI 3002004310 [6] guidance, as well as NUREG-1764 [5]. Figure 22 shows the results of this initial project screening and leverages the same analysis tool used to produce Figure 21.

HFE GRADED APPROACH CHECKLIST (Based upon EPRI 3002004310 Form F-02)

Assessment of Potential Risk to Plant Safety and Economic Operation

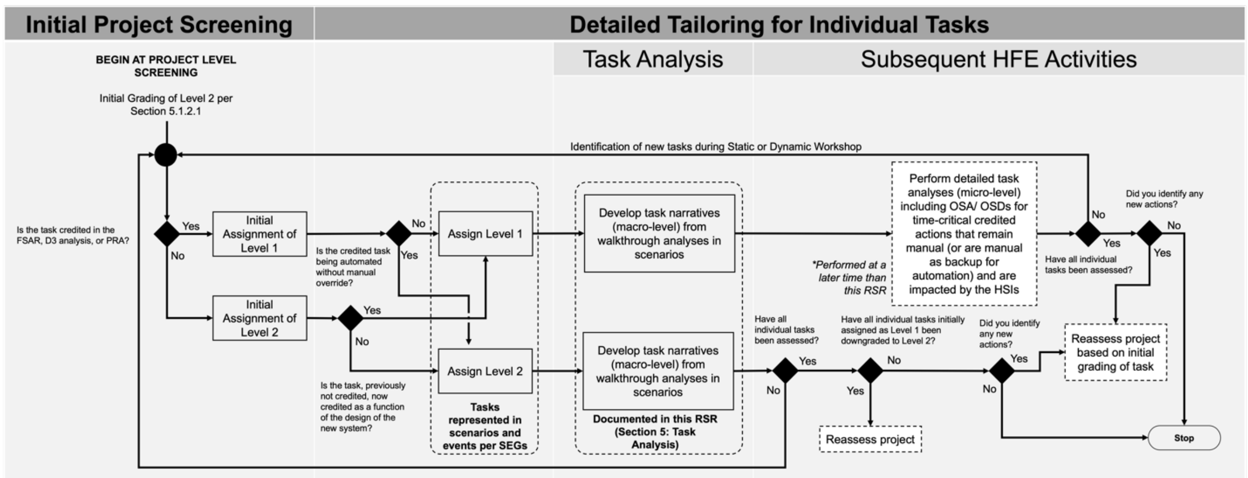
2.0 Evaluation of Secondary Factors	**High**	**Medium**	**Low**	
2.1 Scope and magnitude of the change from an HFE standpoint				
2.1.1 Number of HSIs affected (describe):	[ ](C)	[ ](C)	[ ](C)	[ ](C)
2.1.2 Number of tasks affected (describe):	[ ](C)	[ ](C)	[ ](C)	[ ](C)
2.1.3 Number of personnel affected (describe):	[ ](C)	[ ](C)	[ ](C)	[ ](C)
2.1.4 Degree of change to HSIs (describe):	[ ](C)	[ ](C)	[ ](C)	[ ](C)
2.1.5 Degree of impact on tasks (describe):	[ ](C)	[ ](C)	[ ](C)	[ ](C)
2.2 Complexity of the change from an HFE standpoint				
2.2.1 Complexity of the HSIs being modified or the modification itself (describe):	[ ](C)	[ ](C)	[ ](C)	[ ](C)
2.2.2 Complexity of the affected tasks (describe):	[ ](C)	[ ](C)	[ ](C)	See 2.1.5.
2.2.3 Complexity of the technology involved (describe):	[ ](C)	[ ](C)	[ ](C)	[ ](C)
2.3 Uncertainty associated with the HFE aspects of the change				
2.3.1 Level of industry experience with the change and equipment used (describe):	[ ](C)	[ ](C)	[ ](C)	[ ](C)
2.3.2 Level of experience of plant personnel with the equipment used (describe):	[ ](C)	[ ](C)	[ ](C)	See 2.3.1. and 2.2.3
2.3.3 Completeness of HFE documentation for system being modified (describe):	[ ](C)	[ ](C)	[ ](C)	See 2.2.1 and 2.2.3.
2.3.4 Difficulty of the affected tasks (describe):	[ ](C)	[ ](C)	[ ](C)	[ ](C)
2.4 Conclusion on adjustment due to secondary factors	[ ](C)	[ ](C)	[ ](C)	
Final HFE Level (initial level adjusted if appropriate based on secondary factors)	[ ](C)	[ ](C)	[ ](C)	

Figure 22. Evaluation of secondary factors and establishment of final HFE Project Level.

The results in Figure 22 indicated a final HFE level screening of the project to be Level 2 (i.e., medium potential nuclear safety risk and economic risk; there is no anticipated personal safety risk).

5.1.2.2 Detailed Tailoring of Specific, Individual Tasks in the Human-System Interface Design Phase

Figure 23 illustrates the process followed for specific task identification and tailoring the TA following a graded approach.



Note. Tasks not impacted by SR Upgrade were noted as a Level 3 (little to no impact) and were not considered for subsequent HFE analysis.

Figure 23. Task screening and tailoring process for TA.

The first step was to identify the specific tasks impacted by the modification. The task identification and screening process was accomplished by engaging with LGS training SMEs who identified all the known tasks performed inside and outside the MCR from an Institute of Nuclear Plant Operations required methodology that produced specific LGS tasks and DIF scores, as provided in Appendix C. The screening of these specific tasks was based on whether these tasks were impacted by the SR I&C upgrade project using criteria such as (also see Section 4.1.3):

- Impacts to the operator HSIs inside the MCR
- Changes to workplaces where operators use HSIs, if the changes could impact human performance
- Changes that do not modify HSIs but could have other potential impacts on operator tasks (e.g., system changes that reduce the amount of time available for an operator to perform a task).

Next, tailoring the graded approach was performed at the individual task level. While the initial project-level grading was assigned a Level 2, tailoring of specific tasks was performed (refer back to Figure 23). Tasks that were not impacted per criteria above were considered a Level 3 and were not considered in subsequent TA walkthroughs; these tasks will be reviewed via expert evaluation by LGS to determine the impacts of these tasks from the upgrades. Tasks were evaluated in the TA cognitive walkthrough analysis and were further determined as being important (Level 1) or of lower significance (Level 2) based on whether the tasks were credited in the LGS UFSAR [30] or D3 analysis [31]. That is, if the screened-in task was credited, it was initially assigned Level 1. If not, it was initially assigned a Level 2.

Uncredited tasks (Level 2), or any new tasks that could as a result of this upgrade rise to a level where they were identified as safety significant (in the UFSAR or the D3 Analysis), would be tailored up to or established as Level 1 tasks. Likewise, previously credited tasks that would be completely automated without any manual intervention would be assigned Level 2. As of the writing of this report, no existing tasks have been upgraded and no new Level 1 tasks have been identified. No previously identified Level 1 manual tasks have been automated and downgraded to Level 2.

The final assignment of being Level 1 or 2 determined the level of rigor in applying TA. All Level 1 and 2 tasks were evaluated at a macrolevel through the cognitive walkthroughs documented in this RSR. The identified credited manual tasks, assigned Level 1, were further tabulated for subsequent HFE analyses (i.e., subsequent micro-level analysis) and are listed in Table 4. While time available was qualitatively assessed in this RSR, later iterations of the TA when the HSI design becomes more detailed will apply OSAs and OSDs, following guidance described in Attachment A, “Guidance for evaluating Credited Manual Operator Actions” to NUREG-0800, Revision 3 (2016), Chapter 18, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition – Human Factors Engineering” [34]. The results of the future OSAs and OSDs will evaluate the time required to perform credited manual actions and compare to the time available to determine whether the manual operator actions can be accomplished correctly, reliably, and within the time available.

Table 4. UFSAR and D3 credited tasks significantly impacted by the modification identified by the TA.
[

]$^{(C)}$

[

]^(C)

Impacted tasks were also identified from the PRA. The number identified was small (five) and the degree to which they are impacted is generally not significant. Each PRA-identified impacted task, along with the degree to which they were addressed in the scenarios selected for the TA workshop, is discussed briefly below.

1. [

]^(C)

Table 5. Basic event changes to explore the impact of the human error for failure to depressurize - Sensitivity Case 1 (1).

[

]^(C)

Table 6. Basic event changes to explore the impact of the human error for failure to depressurize – Sensitivity Case 1 (2).

[

]^(C)

2. [

]$^{(C)}$

3. [

]$^{(C)}$

4. [

]$^{(C)}$

5. [

]$^{(C)}$

5.1.2.3 Develop High-Level Task Descriptions and Select Method

A common approach to TA is to develop high-level task descriptions that can be further decomposed to the level of detail necessary to identify task performance requirements [6]; this decomposition is reflected in Figure 16. TA is generally considered to extend from the results documented in FRA & FA. Thus, the task identification and risk significance assignment were used to develop and refine scenarios described previously in Section 4.1.3. Each scenario contained higher-level tasks (i.e., managing specific plant events) in which the specific tasks were grouped in a logical manner by LGS operations and training SMEs to ensure the context to which each task performed was considered. The higher-level tasks and scenarios were documented in simulator exercise guides (SEGs) and served as the basis for detailed TA (also see Section 4.1.3).

These higher-level tasks served as a goal-oriented approach in managing the plant in a way that required performing specific tasks from Appendix C. The benefit of this approach was added contextual accuracy in which the tasks were observed. That is, tasks are often not performed in isolation but are generally performed to accomplish a specific goal that can be characterized through events and scenarios [6]. A group of related tasks used to accomplish a goal (high-level task) is considered an event. Related events can be further grouped into scenarios. Furthermore, the scenario-based approach allowed the team to sample tasks based on their uniqueness and level of impact by the modification. For example, while there several different tasks associated with maintenance testing of the impacted systems, it was possible to sample a single task that was representative of the entirety of tasks associated with maintenance testing, as the specific changes to these tasks were similar in nature.

The primary TA methods selected are documented in Table 7 below. All Level 1 and 2 tasks were grouped into specific scenarios that contained individual higher-level tasks, or events. This composition of tasks and events were documented in SEGs to which the hierarchical relationship was clearly defined through a tabulated hierarchical task analysis (HTA) format. Cognitive walkthroughs were performed at the simulator facility with two licensed operators (a CRS and an RO) and facilitated by human factors engineers. The specific methodology is described in the next section. Level 1 tasks will be further analyzed in later HFE activities using OSA and OSDs when the design is matured.

Table 7. TA method selection.

Level 3 Task	Level 2 Task	Level 1 Task
Primary TA Methods		
• Expert evaluation	• HTA (Grouping tasks by events and scenarios in SEGs) • Cognitive walkthrough	• HTA (Grouping tasks by events and scenarios in SEGs) • Cognitive walkthrough • *OSA and OSD
Primary TA Activities		
• Screened out of SEGs • Review of previous TA	• Screened-in SEGs and evaluated via cognitive walkthroughs with scenarios • Develop task narratives to address macrolevel task impacts	• Screened-in SEGs and evaluated via cognitive walkthroughs with scenarios • Develop task narratives to address macrolevel task impacts • Identify credited manual tasks from UFSAR, D3 analysis, and PRA • *Evaluate credited tasks in later HFE activities to address micro-level considerations such as time required and time available to perform tasks
Primary TA Outputs		
• No formal TA outputs	• Task narratives (see Section 5.1.2.4.4.4)	• Task narratives (see Section 5.1.2.4.4.4) • List of important HAs (refer to Table 4) • *OSA and OSDs for credited tasks
Note: * indicates that the method will be performed in later HFE activities such as the Dynamic Workshop.		

5.1.2.4 Apply Methods and Develop Detailed Task Descriptions

The primary TA method used was a series of walkthroughs from the nine developed scenarios in the HSSL glasstop simulator testbed. A walkthrough is a knowledge elicitation technique where a domain expert (i.e., also referred to as SMEs) demonstrates a set of tasks (i.e., often using procedures) to describe it, highlighting potential issues or identifying the important actions (see "A Guide for Selecting Appropriate Human Factors Methods and Measures in Control Room Modernization Efforts in Nuclear Power Plants" [37]). The walkthroughs were performed by one CRS and one RO from Limerick and facilitated by a human factors engineer at INL and a training SME from Limerick. Additionally, there were several other key staff available from Constellation (i.e., training and engineering), as well as vendor (i.e., Ovation and Common Q). The walkthroughs were facilitated by presenting the key impacted tasks, including important HAs, to operators and having the training SME facilitate the key events from the scenarios in which the impacted tasks would be performed. Operators demonstrated and discussed what specific tasks they would need to perform to address each event (e.g., managing a LOOP) with both the existing and new state MCR. As described in Section 5.1.1.2.3, the simulator was configured to present both the current boards and new HSIs to allow operators to discuss the impacts of changing the HSIs in performing the identified tasks. The crew also had access to their procedures, including TRIPS, as hard copes (Figure 24).

Figure 24. Crew procedure use during TA Workshop.

The training SME from Limerick was able to run aspects of the scenario and pause to add additional context to the data collection. Digital HSI mockups, such as with the PPS console (center of Figure 24), provided clickable renderings of the conceptual HSIs for added context. Furthermore, a large screen monitor adjacent to the MCR layout presented the anthropometrically accurate 3D model of the MCR (see Figure 18) to aid in the discussion related to positioning of VDUs and anthropometric considerations with the modifications. The model contains ergonomic mannequins that could reflect 5th percentile female and 95th percentile male engineering design characteristics to evaluate sightlines and reach using NUREG-0700 [36].

5.1.2.4.1 Task Analysis Workshop Objectives

The primary focus of this TA workshop was to:

- Present prototype HSIs (VDUs and hosted displays)
- Evaluate the use of these displays and how they are presented to the operators (relative physical arrangement, navigation, etc.) so that they can be used to accomplish their tasks with the new systems
- Evaluate the current conceptual arrangement of the new HSIs as depicted in the 3D product model, as shown in Figure 18
- Obtain interactive feedback from operators
- Use the output to support additional workshops (i.e., Static and Dynamic Workshops), and directly drive the Westinghouse Electric Company (WEC) development of displays hosted on VDUs, aid in placing MCR VDUs to promote optimal use, identify any sizing issues, etc., as shown in Figure 25.

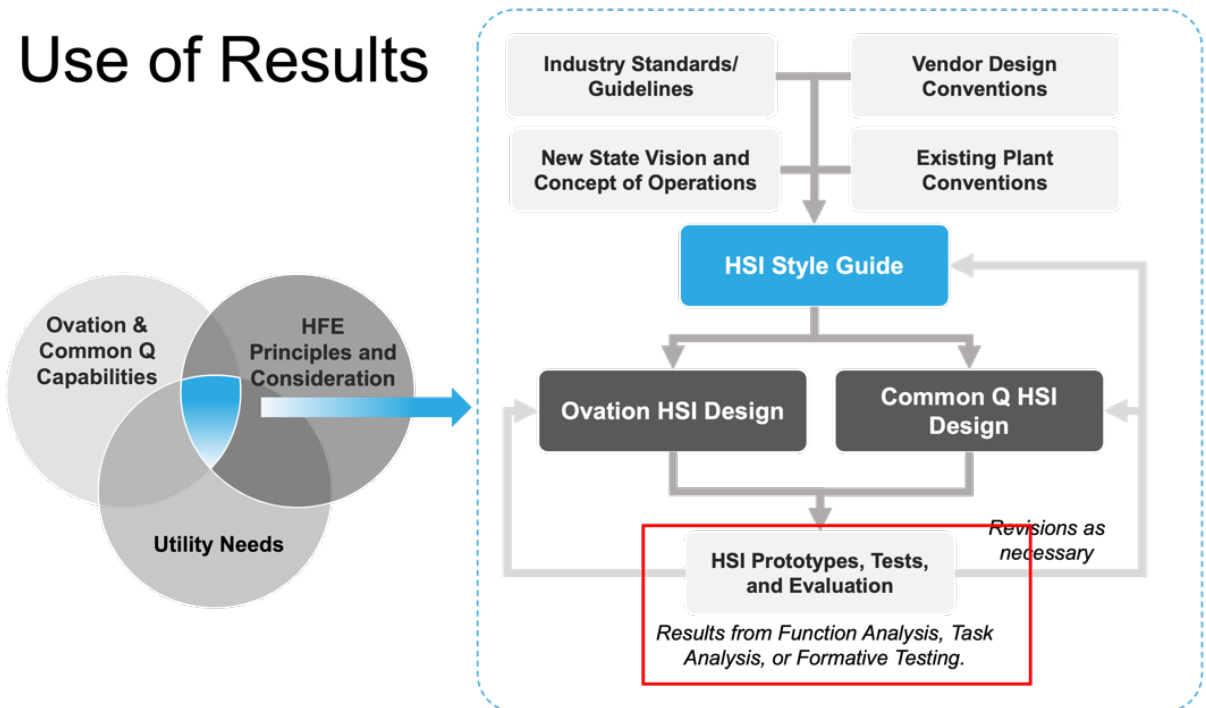


Figure 25. Use of TA results in relation to developing the HSI Style Guide.

5.1.2.4.2 Design Team

Table 8. TA design team.

INL	Constellation LGS
Tina Miyake (Human Factors) Casey Kovesdi (Human Factors) Paul Hunton (I&C and Human Factors) Rachael Hill (Human Factors) Jeffrey Joe (Human Factors) Brandon Rice (Simulator Lead) Tim Whiting (Prototyping) Jeremy Mohon (Human Factors) Stacey Whitmore (Prototyping) Jacob Lehmer (Prototyping) Thomas Ulrich (Human Factors and Prototyping) Robert England (I&C)	Paul Krueger (Operations Support) Wes Henne (RO) Sager Patel (CRS) Scott Schumacher (Site Engineering) Mark Samselski (Design Engineering) **Westinghouse (WEC)** Daniel Zenger (Ovation SME) Jordan Gruszkowski (Common Q SME)

5.1.2.4.3 Agenda

DAY 1 – MAY 10, 2022			
Time (Eastern)	**Activity**	**Location**	**Role**
07:30–08:00	**Arrive at INL** LGS and WEC arrived at INL.	Willow Creek Building	All
08:00–9:30	**Introductions, Overview, Agenda, and Objectives** Introductions were made. Next, INL provided an overview of the facility followed by a safety brief, an overall agenda of the workshop, and an overview of the TA workshop to align the team on: • The HFE Program Plan and introduction to TA • Key Findings from the FRA & FA workshop • The goals of TA and this workshop • An overview of the Westinghouse Ovation and Common Q capabilities.	Energy Innovation Laboratory	1. INL (Paul H) (Jeffrey) (Casey)
9:30–12:30	**Perform Familiarization and Walkthrough Analysis for Scenario 1** Overview and familiarization of the HSSL simulator. Approximately 3 hours were given for a familiarization scenario and Scenario 1, including a 30–60 minute discussion after both conditions.	Energy Innovation Laboratory	All
12:30–13:30	**Lunch**		All
13:30–17:30	**Perform Walkthrough Analysis for Scenarios 2–3** • Approximately 2 hours for each scenario with 30–60 minutes discussion each.	Energy Innovation Laboratory	All
Note 1: Breaks were taken as needed. Note 2: All times were approximate.			

DAY 2 – MAY 11, 2022			
Time (Eastern)	**Activity**	**Location**	**Role**
08:00–12:00	**Perform Walkthrough Analysis for Scenarios 4–5** • Approximately 2 hours for each scenario with a 30–60 minute discussion each.	Energy Innovation Laboratory	All
12:00–13:00	**Lunch**		All
13:00–17:00	**Perform Walkthrough Analysis for Scenarios 6–7** • Approximately 2 hours for each scenario with a 30–60 minute discussion each.	Energy Innovation Laboratory	All
17:00–17:10	**End of Day Recap**	Energy Innovation Laboratory	All
Note 1: Breaks were taken as needed. Note 2: All times were approximate.			

DAY 3 – MAY 12, 2022			
Time (Eastern)	**Activity**	**Location**	**Role**
08:00–12:00	**Perform Walkthrough Analysis for Scenarios 8–9** • Approximately 2 hours for each scenario with a 30–60 minute discussion each.	Energy Innovation Laboratory	All
12:00–13:00	**Lunch**		All
13:30–17:00	**Static Display Review** • Review concept displays used for the workshop. • Identify changes based on the nine scenario walkthroughs. • Review proposed alarm changes to Ovation-based annunciators. • Generate a list of all Ovation overview- and system-level displays that will need to be developed in subsequent design activities. • Generate a list of all PPS displays that will need to be developed in subsequent design activities. • Identify existing resources that will serve as inputs into identified displays (i.e., instructor station displays, PPC displays, etc.).	Energy Innovation Laboratory	All
Note 1: Breaks were taken as needed. Note 2: All times were approximate.			

DAY 4 – MAY 14, 2022			
Time (Eastern)	**Activity**	**Location**	**Role**
08:00–12:00	**Static Display Review (Cont.) and Wrap-up Discussion** • Review concept displays used for the workshop. • Identify changes based on the nine scenario walkthroughs. • Review proposed alarm changes to Ovation-based annunciators. • Generate a list of all Ovation overview-level and system-level displays that will need to be developed in subsequent design activities. • Generate a list of all PPS displays that will need to be developed in subsequent design activities. • Identify existing resources that will serve as inputs into identified displays (i.e., instructor station displays, PPC displays, etc.). • Close out any items not covered in previous scenario debriefs or static display review. • Action items will be captured and distributed to the team.	Energy Innovation Laboratory	All
Note 1: Breaks were taken as needed. Note 2: All times were approximate.			

5.1.2.4.4 Detailed Methods

5.1.2.4.4.1 Introductions, Overview, Agenda, and Objectives

After LGS and WEC arrived at INL, the workshop began with introductions and a facility safety brief. The overall workshop agenda and objectives were provided to ensure team alignment. Next, key findings from the FRA & FA workshop were summarized and presented (see Section 4.1.5) to ensure that these topics were addressed in walkthrough analyses covering the nine scenarios.

INL covered the goals of TA and this workshop and provided an overview of the TA methodology. The team was reminded that the workshop was intended to evaluate the impacts of technology on the tasks and not to evaluate the crew specifically. All data was anonymized through participant IDs and data aggregation where possible.

5.1.2.4.4.2 Perform Walkthrough Analysis

Figure 26 illustrates the workflow performed for the walkthrough analysis.

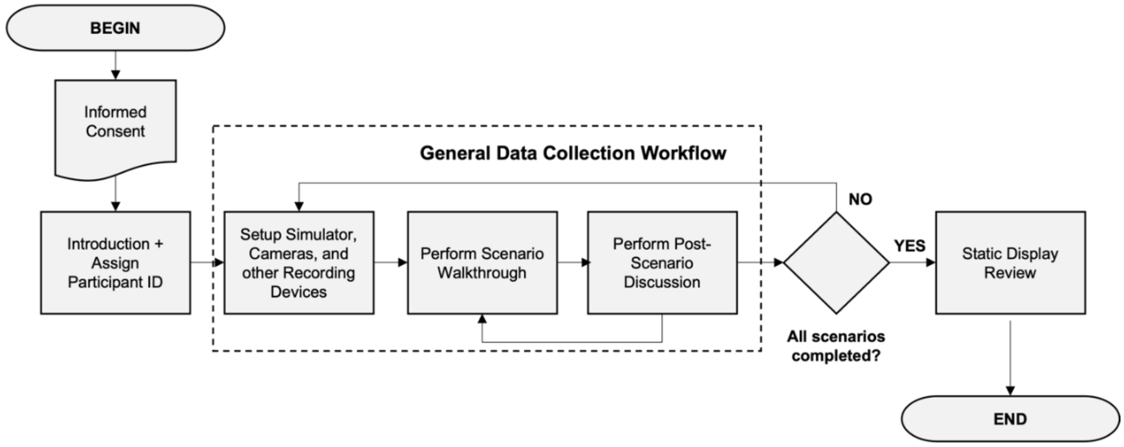


Figure 26. Walkthrough analysis general workflow for the TA workshop.

5.1.2.4.4.2.1 Informed Consent

Informed consent was verbally administered to the crew prior to the walkthrough analysis.

5.1.2.4.4.2.2 Introduction and Participant Identification Assignment

Data collection was anonymized and aggregated throughout. Operators were instructed to perform a think aloud approach (i.e., verbalize their thoughts) regarding their experience using the existing and new indications and controls during the scenario. Operators were reminded that:

- Their participation was being requested because of their knowledge and expertise
- The information they provide would be used to guide the HSI design
- Their opinions would guide preferences and requirements for the new designs
- The information being collected would be used to design or evaluate the HFE aspects of the HSIs and **NOT to evaluate their performance**
- The anonymity of personnel would be maintained
- Their comments would be treated as anonymous and coded using a Participant ID scheme.

During this time, LGS provided supporting details to help operators align to the objectives of these walkthroughs and expectations when performing these scenarios. While these introductions were performed once, reminders were given as often as necessary to ensure operators were aligned with the workshop goals.

5.1.2.4.4.2.3 Simulator and Data Collection Setup

The simulator specialists prepared simulator for each scenario by setting up initial conditions and other tasks (e.g., preparing the SEGs) necessary to run the scenario and enable video recording. The simulator specialist provided a cue when the scenario began and ended. INL human factors staff prepared data collection tools, printed procedures, and cameras as the primary recording device. Each INL staff was assigned different primary roles for collecting notes.

5.1.2.4.4.2.4 Perform Walkthroughs

During the walkthrough, the simulator was stopped at steps in the procedure where new functions were added, eliminated, or changed. The operators and others in attendance were asked to discuss these possible changes from existing practices. INL human factors staff collected verbal and observational data in the data logger while also facilitating the think aloud technique per scenario. Figure 27 presents a photograph taken during one of the scenarios performed for the walkthrough analysis. As seen, operators walked through key tasks within the defined events and scenarios from the SEGs. The MCR arrangement was faithfully represented to match the board configuration of the actual MCR. Both the existing and new states were presented to allow operators to discuss how they perform tasks now and how the upgrades will impact these tasks. Human factors staff collected observational and self-report data from the walkthroughs using a combination of recording devices.

Figure 27. Photograph of the TA Workshop walkthrough analysis.

5.1.2.4.4.2.5 Perform Post-Scenario Discussions

The post-scenario discussion was performed in concert with the walkthrough analysis; this is reflected in Figure 26 from the small iterative loop between performing the scenario walkthrough and performing the post-scenario discussion. During the post-scenario discussion, INL human factors staff facilitated a semistructured set of questions. The 3D model was also used, showing the planned modifications, to focus on the discussion where needed. General questions included:

The plant is highly dynamic and operator actions often occur in parallel (particularly during casualty events).

1. Do the new upgrades disrupt the operators' ability to perform parallel processing?
2. Do the new upgrades disrupt the operators' ability to perform teamwork diagnosis and response execution?

3. How do the proposed modifications alter individual and team situation awareness concerning parallel processing?
    - Do the overviews provide the right level of information to enable team situation awareness? Is there additional information needed?
    - Is the location of the new PPS displays adequate or not?
    - Will the automation enhancements enable improved situation awareness or not?
    - Are there human error traps associated with these upgrades that may limit team awareness?

In many situations, operators can achieve successful plant safety and operational outcomes in more than one way when following the same set of procedures.

4. Do the new upgrades prevent operators from following specific actions and procedures where more than one path is permissible?
    - Is the navigation appropriate or not appropriate for PPS?
    - How should the navigation structure for Ovation control displays be designed?

Operators leverage the existing "flat topology" of indications and controls to enable parallel processing and multipath diagnosis.

5. Do the proposed modifications support or disrupt the "flat topology" attributes of the existing control room used for diagnosis?
    - If so, how?
6. Any additional trending capabilities to include?

There are highly manual tasks (e.g., controlling pressure via SRVs) where operators are required to remain in a particular location at the control board.

7. Is situational awareness improved or inhibited by the reduction of "ping-ponging" around the MCR?
8. Do the automation enhancements support or not support workload management previously challenged by highly manual tasks (e.g., controlling pressure with the SRVs)?
9. What actions and processes have been improved with the proposed modifications?

Additionally, human factors staff facilitated discussion on the impacts to specific important HAs tasks from the modification. This discussion was based on the seven identified important tasks from the Chapter 15 UFSAR [30] and the D3 analysis [31] as well as the five identified important tasks from the PRA [41] that were significantly impacted from the modifications (refer to Table 4). These tasks were reviewed in terms of the impacts to the:

- Alarms
- Decision-making
- Information
- Controls
- Communication and teamwork
- Workload and time
- Impacts to other tasks.

Operators self-reported on these topics above regarding how the existing MCR configuration facilitates task completion and then discussed the impacts of the upgrades along these topics. These findings represent the task requirements and additional considerations described in Section 5.1.2.4.4.4.

5.1.2.4.4.3 Static Display Review

After the nine scenario walkthroughs were completed, a static display review was completed. This activity spanned the course of Day 3 and 4, with the intention to address the following items:

- Review concept displays used on workshop
- Identify changes based on the nine scenario walkthroughs
- Review proposed alarm changes to Ovation-based annunciators
- Generate a list of all Ovation overview- and system-level displays that will need to be developed in subsequent design activities
- Generate a list of all PPS displays that will need to be developed in subsequent design activities
- Identify existing resources that will serve as inputs into identified displays (i.e., instructor station displays, PPC displays, etc.).

The review focused on the overview Ovation displays (Day 3) and PPS displays (Day 4). The display review was facilitated by INL human factors staff where each display was presented on a large monitor and operators provided comments, based on their experience in the walkthroughs, regarding the completeness and format of the displays. Ovation and Common Q SMEs were available to provide feedback on the design characteristics of these platforms.

5.1.2.4.4.4 Identify Task Requirements and Additional Considerations

The results of the walkthrough analyses for the nine scenarios created task narratives for each of the primary events. Figure 28 presents the format, which is based on Figure 5-1 in NUREG-0711 [1]. One of the key differences with the narrative tables used here was that the task narratives described not only a summary of current task requirements but also the impacts of these task requirements based on the modifications. The left column in Figure 28 describes existing task considerations whereas the right column describes the impacts of these task considerations from the modifications. The intent of these tables was to understand the task requirements at a macrolevel, specifically in understanding how the modifications to alarms, HSIs, and controls will impact crew performance, situation awareness, communication, and workload. In subsequent activities, like the dynamic workshop, the Level 1 tasks in Table 4 will be further analyzed in later HFE activities using OSAs and OSDs as the suite of Ovation and PPS displays are more complete.

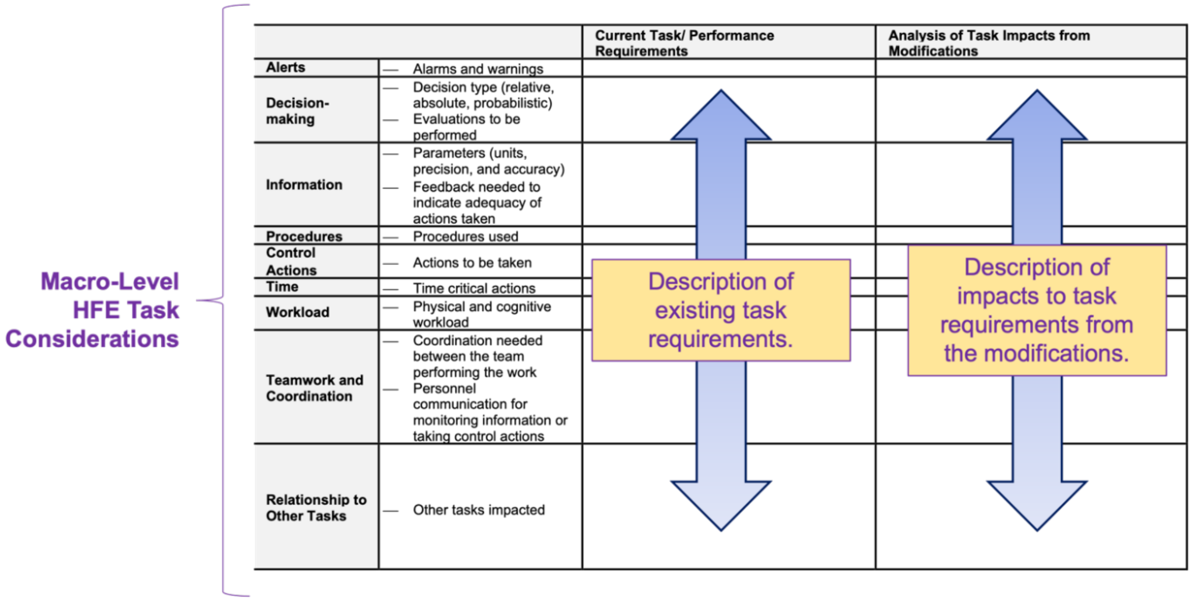


Figure 28. Task description tables.

5.1.2.5 Cognitive Modeling Software

Cognitive modeling software (Cogulator [38]) supported specific user interactions with the PPS displays to estimate the time required to perform specific actions with the PPS, including navigation and operating soft controls. The intent for using Cogulator here was to provide preliminary estimates of task completion time for simple interactions to support subsequent TAs planned in later activities, such as the dynamic workshop. Cogulator is an open-source script-based program that uses goals, operators, methods, and selection rules to generate predicted task times.

5.2 Task Analysis Results Summary

Key findings from the TA workshop are presented below. Detailed findings are described in Appendix B.

1. Walkthroughs and reviews were performed for all scenarios from the FRA & FA workshop. Specific tasks requiring manual actions were reviewed in the context of the HSSL and prototype VDU displays and display navigation. Those in the workshop with operating experience determined that those actions could be properly performed using the design concept presented in a manner that enabled correct, more informed, and more timely operator actions than the current design.
2. New PPS and DCS operator VDUs need to be grouped together in a way that facilitates their coordinated use. The workshop participants determined that there should be two groups of the four divisional PPS VDUs, with each group having a collocated DCS (Ovation) VDU. Each of these two groups was euphemistically called a “5 pack” as shown in Figure 29 below.

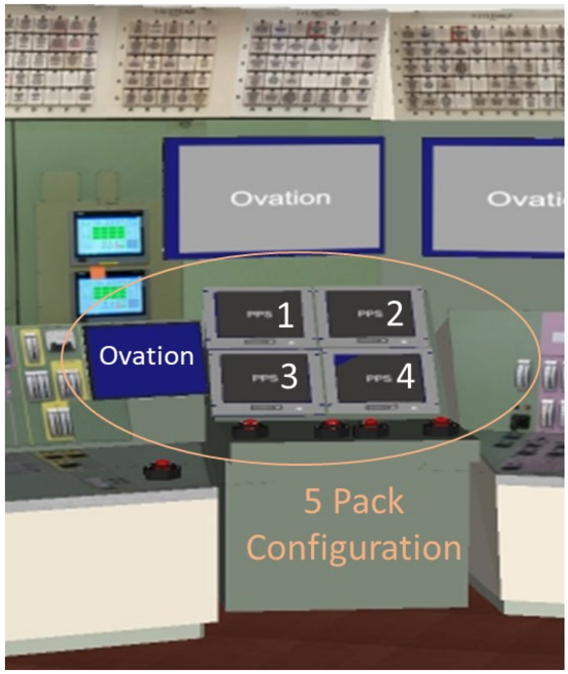


Figure 29. “5 Pack” PPS and DCS (Ovation) workstation in current concept design location.
(as mocked up during the TA Workshop)

3. The primary (RO) 5 pack needs to be located in close proximity to the 603 panel to allow for coordinated PPS and other safety system controls. The resultant configuration along with the in-scope automated operator aids will allow the RO to perform the majority of his responsibilities from this location.
4. The primary group of PPS VDUs need to be mounted in a way that it:
    a. Provides for the functionality of Finding 3.
    b. Does not obstruct the ability of the RO to view information on the “back panels” of the MCR in front of them.
    c. Optimizes the use of the Ovation “group view” displays.
    d. Facilitates the use of both touchscreen and pointing device use by the operator.
    e. Is optimized as much as possible to meet the goal of providing proper ergonomics for the 5th percentile female and the 95th percentile male (per NUREG-0700 [36]).
    f. Allows for the RO and PRO to coordinate their actions.
    g. Allows for the CRS to best oversee the actions of the RO and PRO.
    h. Following LGS procedure, an SME in panel construction needs to be added to the team to help establish the MCR arrangement to ensure that the optimized design takes into account not only I&C and HFE attributes but also reflects panel structural concerns (e.g. fitment, seismic).
5. The secondary (PRO) PPS and Ovation VDU 5 pack needs to be located such that
    a. The PRO can use this location to perform monitoring and control actions during casualty and complex operating conditions.
    b. It can be separated from the RO 5 Pack VDU location to prevent congestion during both casualty and complex plant evolutions.
    c. It can be located such that the CRS and STA
        i. Can observe and direct operator actions at the PRO VDU 5 pack

ii. Can use the PRO 5 Pack PPS VDUs as a “group view display” in the event that Ovation is not functional (loss of the Ovation VDU functionality).

iii. Can have access to RG 1.97 variable information (either “continuously viewable” or “continuously available” – More on this in Finding 8).

6. PPS and DCS VDUs in the “5 Pack” for both the RO and PRO need to support both touchscreen and pointing device functionality. Touchscreen enables rapid casualty response (display page navigation and rapid control action). The pointing device will provide an augmented capability for CRS oversight of routine and non-casualty RO and PRO operations.

7. To best address Finding 2–6 together, the conceptual layout provided in Figure 30 was developed.

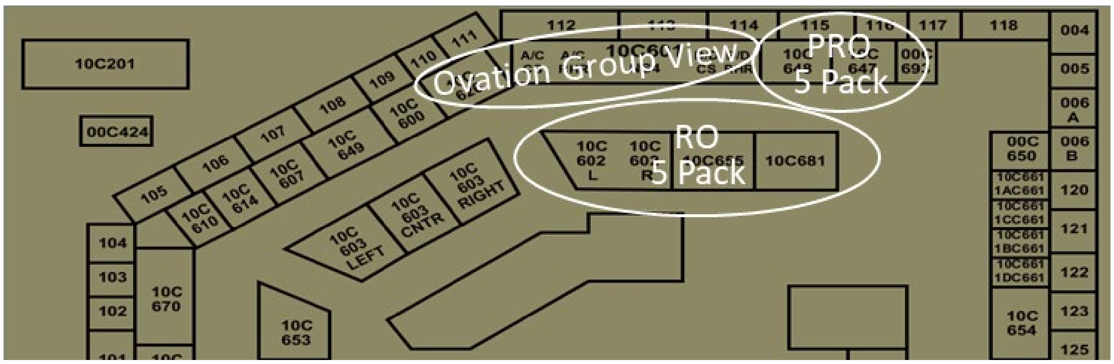


Figure 30. PPS and DCS Workstations overlaid on the MCR layout drawing.

This conceptual layout:

a. Locates the RO “5 pack” to a location within the oval shown above that would be driven by efforts to minimize the project cost and provide for necessary structural modifications to the panel.

b. Identifies Ovation DCS group view displays as currently located in the upgrade design concept,

c. Places the PRO “5 pack” (as already described in Finding 5) as shown above.

Notional 3D model arrangements showing approximate VDU locations as depicted in Figure 30 are shown in Figure 31 below.

Figure 31. Notional MCR layout incorporating TA key findings.

Note that this notional arrangement:

- Provides optimized ergonomics that better addresses the guidance for the 5^{th} percentile female and 95^{th} percentile male
- Supports better coordinated control and supervision of PPS and DCS (Ovation) functionality for the current modification
- Supports better coordinated control and supervision of PPS and DCS (Ovation) functionality any future modifications that would migrate obsolete I&C functionality to either PPS or DCS.

The notional arrangement provided in Figure 31 is for illustrative purposes only. It has not been evaluated from a constructability point of view and may not represent the final MCR layout implemented by the LGS SR I&C Upgrade Project.

8. PPS VDUs:

    a. Have the capability to continuously present certain key variables (in the display headers or footers) and navigate to others.

    b. Are limited in number (two per safety division, eight total).

    c. Are required to be able to provide MCR operators with sufficient capability to supervise and control the plant in the event of a loss of Ovation DCS.

    This mix of capabilities, limitations, and requirements for the PPS VDUs raises a question with regard to legacy RG 1.97 [39] licensing commitments for continuously presenting certain variables (continuously viewable). In the legacy design, these continuously viewable indications are largely provided with single point devices (meters, gauges, strip chart recorders, etc.). For such legacy variables that are subsumed within the PPS, it may be more advantageous for plant operation to make some or all of these variables "continuously available" to the operator through simple navigation. There could also be separate displays (software images) developed for presentation on PPS VDUs that contain these variables. Instead of one or more of these displays being "fixed" to particular VDU(s), and thus severely limiting the usefulness of the limited number of PPS VDUs, their presentation could be controlled by policy and procedure based upon plant conditions. Both an operations and a licensing evaluation need to be made with regard to making RG 1.97 variables continuously available vs. continuously viewable.

There is precedence for the use of "continuously available indications and alarms" as well as for a "limited number of fixed position controls" in the AP1000 Design Control Document, Section 18.12 "Inventory" in Section 18.12.2, "Minimum Inventory of Main Control Room Fixed Displays, Alarms, and Controls" [40].

9. Replication of the subset of PPS displays used to monitor and control the plant on the DCS (Ovation). CRS identified that it would be advantageous (and easiest) to replicate the subset of PPS displays used by the RO to operate the plant and diagnose casualties on Ovation. That way, the CRS would be able to independently navigate to see the same information in the same format that the RO is seeing. It was stated to that the effort to reformulate the presentation of such PPS information on Ovation would be significant and of limited additional value. Deciding exactly which PPS displays are to be replicated is a future activity.
10. Need to identify how valid "offscale – low" and "offscale – high" sensor values are presented on HSIs for this upgrade. There are operating conditions where sensors will detect such values from the field. This expected operational functionality is differentiated from a sensor producing an "offscale – low" or "offscale – high" due to a sensor failure or communication failure to the sensor. Such a sensor or communication failure typically would appear in Ovation as "bad quality" (magenta). This is a general issue for indications that can show either "offscale – low" or "offscale – high" without showing "bad quality."
11. The ability of the upgrade to provide field data previously unavailable in the MCR will reduce RO, PRO, and CRS uncertainty with regard to these values. This will also improve operator time response to plant conditions.
12. RO & PRO will be performing actions currently performed in the MCR along with actions currently performed by operators outside the MCR. This tends to increase RO workload (at least for short periods of time) but is expected to speed up the overall response to the casualty in the MCR. This also frees up operators outside the MCR to pursue casualty response actions to aid in control and recovery.
13. The conceptual layout limited the "ping-pong" movements of the RO in the MCR during the scenarios, because the upgrade tends to centralize indications and controls (RO "5-pack"). It is expected that the PRO "5 pack" will similarly reduce the "ping-pong" motions of the PRO.
14. MCR operators need to be trained on the failure modes of the Common Q and Ovation platforms. These failures would be induced by the partial and complete loss of power to portions of Ovation or Common Q, specific postulated malfunctions within each platform (e.g., loss of an Ovation server), loss of actuator power to a controlled component, or loss of separate whetting power to indications that feed Ovation and Common Q. Some scenario discussions were truncated and left open-ended because the detailed platform failure modes and how they will present themselves in the MCR have yet to be clearly defined in the I&C design.

    Example: Overall, the new Common Q and Ovation designs will provide more reliable SR and NSR I&C indications. Fewer indications are lost (during a loss of power conditions) and the ones that remain are being consolidated. Control power to field components, however, is largely unaffected by the upgrade. The number field components that lose control power is largely unchanged by the modification during the same loss of power conditions as described above.
15. It was noted that operators participating in the workshop did not have a full understanding of the detailed operational boundaries of the modification. This will need to be rectified as the HSI design effort continues forward.

16. The current use of the MCR wall panel provides MCR operators with significant operation awareness that supports a common "mental model" at a distance. This is accomplished based upon the location of physical system mimics and equipment status indications (lights, meters, digital indications, strip charts, etc.). In most cases, operators can glean significant and valuable plant status information at a distance without having (or being able) to read the associated labels on the panel or the gradations on particular indicators. Plant operators at the workshop identified that the Ovation and Common Q VDUs located on the MCR wall panel could similarly provide such information on "overview displays" on the MCR back wall panels. If VDU display information were properly grouped and arranged and with sufficient training, this "at a distance" assimilation of information could be significantly augmented. Text and indications on these "overview displays" would likely be provided in two different sizes.
    a. Large text readable at a distance would provide global context for the "overview" displays along with a minimum set of "important" data that would also be directly readable at a distance. Simplified system mimics with indication of active components in those systems would be provided. The use of pictograms (e.g., level indication bars, trend lines) instead of text values would also be preferred. These indications would meet the guidelines from NUREG-0700 [36] for viewing at a distance consistent with the RO and CRS watchstanding positions.
    b. Detailed information, such as labels for components, gradients for indicators, etc., would be provided so that they could be read at a closer distance from the panel standing at "arms reach" from the "overview displays." This would allow for closer inspection during normal operation or, if necessary, during the recognition phase of a plant transient and casualty. Noun name for components may also be considered if they can provide clear and unambiguous identification.

    More detailed TA results can be found in Appendix B – TA detailed results.

5.3 Additional Items Beyond the Scope of the Task Analysis Identified at the Task Analysis Workshop

In addition to the key findings identified in Section 5.2, additional findings important to the overall LGS Unit 1 SR I&C upgrades but not directly within scope of the TA were that:

1. Display development is in its nascent stage. The level of effort to fully define the number, content, layout, and navigation of DCS (Ovation) and PPC (Common Q) displays will be significant. It has not yet been fully bounded. Constellation operations and engineering, along with INL HFE personnel will need to define the needed capabilities and attributes for these displays and navigation with WEC providing bounding limits based upon the capabilities of the two platforms. WEC will provide the final renderings, capabilities, and navigation identified by the team.
2. The optimal way to develop the "artwork" for #1 above and then to translate the result into "operable" displays for the steps below has been established, but not agreed upon by all parties:
    a. Task Support Verification (static with navigation and dynamic to support display and procedure evaluations)
    b. ISV (operable on the simulator and depicting "final" display content, layout, and navigation)
    c. Plant installation (fully representative of the ISV, developed using the associated quality programs for Ovation and Common Q).

    "Operable" is in quotes because the degree of "operability" and associated quality may be different for a–c. Depending upon how the team decides to pursue display development, items (e.g., b and c) could be combined.

5.4 Examination of Important Human Actions

As stated in Section 6.8 of the HFE Program Plan [2], the Important HA element is concerned with HAs that are the most important to safety. HFE efforts for the LGS SR I&C upgrade project are to address Important HAs enveloped within the project, as identified by Constellation. Since this project is performing a modification of an existing plant, identification of Important HAs is not done from a "clean sheet." Rather, the Important HAs for the existing design are known. Furthermore, the existing Important HAs impacted by the upgrade are a subset of those.

Examination of Important HAs for this project started during the FRA & FA. As presented in Section 4.1.2, the FRA & FA planning meeting, task screening had commenced. Screening included not only whether tasks were impacted by the modification but also on tasks that address operator actions as identified either as part of the D3 analysis [31] or that are considered "risk important tasks" from the UFSAR Chapter 15 [30] or the PRA [41]. "Screened-in" tasks were used, along with tasks prioritized by DIF scores provided in Appendix D, to identify and develop scenarios (Section 4.1.3) to be run during the FRA & FA during FRA & FA Workshop. The observation of scenario execution helped the HFE team understand how the MCR operators accomplish these actions and tasks using the current MCR and I&C design.

The TA effort in Section 5 leveraged the results of the FRA & FA effort as inputs. Additional HFE conceptual design work, including the development of a 3D arrangement informed by those inputs (Section 5.1.1.2.1), configuration of the HSSL to approximate the MCR physical changes envisioned in support the upgrade (Section 5.1.1.2.2), and the development of prototype HSI displays and an associated navigation strategy (Section 5.1.1.2.3). These were used to perform the TA Workshop walkthroughs of the same scenarios developed for the FRA & FA workshop.

Using the same scenarios allowed the design team to assess how the aggregate HSI conceptual design presented in the TA workshop would permit operators to properly execute the scenarios. Specific Important HA as communicated by Constellation were captured in Section 5.1.2.1, Table 4, "UFSAR and D3 credited tasks significantly impacted by the modification identified by the TA." Credited tasks from the PRA [41] were also considered as part of this effort. For each TA scenario walkthrough as captured in Attachment B the specific Important HA identified in Table 4 for that scenario are specifically listed and were discussed. For all scenarios, operations representatives stated that all critical tasks for each were discussed. Operators concluded that the notional HSI functionality as presented for each scenario would either not negatively impact or improve operator response for these tasks. This is reflected in Finding 1 in Section 5.2.

While evaluation of Important HAs is complete for the Planning and Analysis Phase for NUREG-0711 [1], Important HAs will be iteratively addressed during the Design and V&V phases. As stated in Section 6.12.1.1. of the Project HFE Plan [2], HSI design static and dynamic workshops are planned to facilitate focused prototype display usability testing. This is a continuation of the TA activity into the design phase. During these workshops, new and impacted important HAs associated with this upgrade will specifically be evaluated following the preliminary validation process as outlined Attachment A, "Guidance for evaluating Credited Manual Operator Actions" to NUREG-0800, Revision 3 (2016), Chapter 18, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition – Human Factors Engineering" [34].

Any new Important HAs will be identified through this process by a screening analysis as described in NUREG-1764 [5]. Identification of any additional Important HAs will also be considered in a manner consistent with guidance in NUREG-0711 [1], where applicable.

It is expected that as part of this effort, OSDs or similar will be employed. This method consists of identifying the key human and system "actors" in scenarios, the interactions between them, and the information (signals) produced by systems that are being accessed by operators. The sequential actions are plotted on a timeline to help decompose functions into tasks, subtasks, and task elements.

This method provides a framework that helps analysts investigate the nature of human interaction with the system, their timely execution of HAs, as well as opportunities for improvement.

As the HSI design converges, Task Support Verification activities will be performed on those HSIs (see Section 7) using procedures that have been modified to reflect the upgrades. It is not anticipated that new HSI graphics functionality incorporated into the MCR by itself would require a change in plant operating procedures. Functional changes, such as the implementation of new control features (including automation), will require procedure changes. HSI and procedure issues identified during Task Support Verification are then dispositioned.

6 MAIN CONTROL ROOM STAFFING AND QUALIFICATIONS IMPACTS OF MODERNIZATION

As stated in Section 6.7, "Staffing and Qualification Analysis," of the HFE Plan [2], it was not expected that the Limerick SR I&C upgrade will fundamentally impact the staffing and qualification requirements for plant personnel. During the performance of the other Planning and Analysis activities as documented in this report, there was no indication from operations personnel that there would be any need to modify the staffing levels of MCR operators or alter their basic qualifications as a result of performing the upgrade as scoped. It is anticipated that, through the optimized HSIs and the addition of the limited number of automated features being added as part of the Project scope, MCR operator cognitive workload will be reduced. Indications and controls impacted by this upgrade will be engineered in such a way as to account for the FRA & FA key findings as captured in Section 4.2.1. While some actions currently taken outside the MCR (e.g., in the AER) will now be performed from the MCR, the cognitive workload in the MCR will not be significantly impacted. This is because those external actions are currently directed by MCR personnel and reported by EOs to the MCR. Having direct MCR access to information and control for the limited items transferred from outside the MCR is expected to improve aggregate operator performance.

It is expected that plant procedures will be impacted and that personnel will need to be trained on the characteristics of the new system's functions and capabilities. Training and Qualification activities are identified in NUREG-0711 [1] and the HFE Plan [2] as design phase activities.

7 VERIFICATION & VALIDATION: ESTABLISH SIMULATOR STRATEGY TO SUPPORT INTEGRATED SYSTEM VALIDATION

Per NUREG-0711, Section 11.1 [1], Integrated System Validation (ISV) is an evaluation, using performance-based tests, to determine whether an integrated system's design (i.e., hardware, software, and personnel elements) meets performance requirements and supports the plant's safe operation. In order to execute an ISV for the Limerick SR I&C Upgrade, a facility needs to exist that is capable of supporting these performance-based tests.

Section 11.4.3 [1] states that the scenarios for ISV should be performed using a simulator, or other suitable representation of the system, to determine the complete design's adequacy to support safe operations. Validation should be performed after the resolution of all significant human Engineering Discrepancies identified in verification reviews.

As part of the project schedule, there are several V&V activities that build on each other that culminate in performing ISV that are summarized in the subsections below.

7.1 Static Workshop(s) – Conceptual Verification

Using the findings in this report and the prototype displays and navigation strategy (Section 5.1.1.2.3) created for and commented on in the TA Workshop (Section 5.1.2.4.4.3) as a starting point, more refined displays that will ultimately be used for ISV will be developed. Working with operations, the types and number of displays necessary to accomplish ISV will be bounded. Prototyping tools, such as those used during display development in preparation for the TA Workshop, will continue to be leveraged to create more refined displays. This will support initial tabletop reviews of displays by the geographically dispersed design team. In parallel with display development, necessary procedure changes to enable the use of these displays will also be made. As these coordinated efforts converge, Task Support Verification can begin. While portions of Task Support Verification may likely be performed in a tabletop environment, conceptual verification of the HSI design will occur during static HSI workshop(s)—one or more as necessary. Scenario walkthroughs will be performed using navigable, static displays on a simulator that can support this purpose. A simulator such as the HSSL (or similar) is desirable for accomplishing the workshop(s) to allow operators to see the refined displays, using modified procedures, in the context of the larger MCR. The ability of operators to accomplish the Important HAs as identified in Table 4 or any potential new Important HAs will also be qualitatively assessed.

7.2 Dynamic Workshop(s) – Preliminary Validation

After the completion of the static workshop(s), additional refinements to the ISV-related displays and procedures will be made as necessary to address issues identified during the static workshop(s). The resultant displays will be dynamically connected to a simulator plant model to allow the presentation of simulator data on the displays. Scenario walkthroughs will be performed using navigable, dynamic displays on a simulator that can support this purpose. Standalone computer equipment may be used to evaluate the display capabilities in conjunction with procedure use. The satisfactory completion of such displays with procedures constitutes a Task Support Verification. A simulator, such as the HSSL (or similar), is desirable for accomplishing the workshop(s) to allow operators to see the dynamic displays, using modified procedures, in the context of the larger MCR.

Dynamic workshops will be used to perform a preliminary analysis and validation on the HSI's developed for this upgrade, following the guidance of Attachment A, "Guidance for Evaluating Credited Manual Operator Actions" to NUREG-0800, Chapter 18 [34]. As discussed in multiple locations in Section 5, OSAs and associated OSDs are to be developed and validated for these manual actions, consistent with the review criteria.

Any final modifications needed to either the ISV-related displays or procedures will be made based upon the dynamic workshops. This will be the final input to rendering the PPS displays using the software application associated with Common Q and the DCS displays using the software application package for Ovation. Display and procedure development beyond those used for ISV support will use the lessons learned and direction established by the above processes to finalize the remaining displays and procedures. The correctness of these will be enveloped within Constellation's procedure development process and WEC's quality processes for HSI design.

7.3 Integrated System Validation

Constellation will provide an MCR simulator of sufficient fidelity to perform ISV for the upgrade. Development activities to ready this simulator for ISV (physical modifications driven by the design of new and modified HSIs, loading of HSI and control system software, and necessary simulator infrastructure modifications to enable this software to support an ISV) are incorporated within the project schedule for the upgrade.

A detailed ISV implementation execution plan, as described in the HFE Plan [2], Section 6.15, will be developed to govern the ISV. Approximately two months before ISV, a readiness review of the Constellation provided simulator will be performed using the ISV implementation plan as a guide. Key readiness items to be assessed during the ISV readiness review are captured in Section 6.16.2 of the HFE Plan [2] and are repeated below indented for convenience.

Preparatory steps will be taken to ensure that all necessary arrangements have been made to enable successful execution of the ISV. These will include (but are not limited to):

- Identification of the operators who will be the subjects who participate in the ISV
- Ensuring operator subjects receive sufficient familiarization training on both the attributes of the design change and revised procedures prior to its execution
- Verification that the new HSIs developed for this upgrade along with associated control emulations associated with the new I&C design have been fully incorporated into the simulator
- A preparatory workshop where a dry run of the ISV will be performed. This dry-run will be performed with operations personnel who will not be ISV operator subjects. HFE program execution operating experience has shown that this is an invaluable step to ensure:
    - Scenarios have been properly selected
    - The simulator is capable of supporting ISV by running those scenarios
    - Simulator training personnel are able to properly run the simulator to execute the scenarios
    - Potential simulation limits that may be encountered during ISV are identified and methods to deal with them are identified in advance
    - Evaluation of any open HFE Issues that may impact ISV execution
    - The necessary procedures are available not just to address the evaluation of the direct scope of the Limerick SR I&C upgrade project but for all systems in the MCR
    - Overall workload in the MCR is properly simulated (e.g., routine communications, work package processing, minor plant issues not directly related to the scenarios)
    - Examination of the use of “time compression” of extended, “low intensity” activities (e.g., a reactor startup) during scenario execution to maximize the access to operator expertise for performing the ISV while accounting for the limited availability of operator subjects
    - The familiarization training provided to operator subjects on the new design and associated procedure changes properly cover the envelope of activities that will be performed during ISV
    - Sufficient HFE SME observers have been identified along with their roles and necessary tools (observation forms, recording devices, etc.) to ensure that necessary data is captured during the ISV
    - Structured ISV scenario and overall “out-briefs” have been preplanned with necessary tools for data capture, which should include not only the operator subjects and the HFE SMEs but also simulator training personnel, the Responsible Engineer, Project Manager, and appropriate Limerick Station management personnel
    - Creation of the final ISV execution plan and schedule based upon information gathered during the workshop.

8 CONCLUSION

This report captures project efforts associated with several HFE Planning and Analysis Phase activities as described in the HFE Plan [2], as captured in Table 9.

Table 9. Planning and Analysis Phase HFE activities addressed by this report.

HFE Plan (6.1) Document Section	Activity	Section in this Document
6.5	Functional Requirements Analysis and Function Allocation (FRA & FA)	4 in its entirety
6.2	“New State” Vision for I&C Upgrades	4.1.1.1.1.1
6.3	Concept of Operations	4.1.1.4 and 4.2.2
6.6	Project Screening and Task Analysis (TA)	5 in its entirety
6.8	Important Human Actions (HAs)	5.4
6.11	Conceptual Design HSI Display & Navigation Strategy	5.1.1.2.3
6.7	Staffing and Qualification Analysis	6
6.9	Verification & Validation: Establish Simulator Strategy to Support Integrated System Validation (ISV)	7

Completion of other Planning and Analysis Phase activities are documented in separate reports, as listed in Table 10.

Table 10. Planning and analysis phase HFE activities addressed by other reports.

HFE Plan Document Section	Activity	Report
6.4	Operating Experience Review (OER)	Human Factors Engineering Operating Experience Review of the Constellation Limerick Control Room Upgrade: Results Summary Report, INL/RPT-22-68703 [3]
6.10	HSI Style Guide	Human-System Interface Style Guide for Limerick Generating Station, INL/RPT-22-68558 [4]

While the Planning and Analysis HFE Plan sections followed the structure of NUREG-0711, its implementation as captured in this report reflects its performance within the larger project. This report, in conjunction with References [2], [3], and [4], completes all HFE activities for the Planning and Analysis Phase as identified in the HFE Plan [2], Table 1, “Summary of NUREG-0711 Activities and their Relationship to Project HFE Activities.” Results from this combined work will be leveraged in the design and V&V phases.

9 REFERENCES

[1] NRC. 2012. “Human Factors Engineering Program Review Model.” NUREG-0711, Rev. 3. Washington, DC: U.S. Nuclear Regulatory Commission.

[2] Joe, J. C., P. J. Hunton, and C. R. Kovesdi. 2022. “Human Factors Engineering Program Plan for Constellation Safety-Related Instrumentation and Control Upgrades, Idaho National Laboratory.” INL/RPT-22-68693, Idaho National Laboratory.

[3] Joe, J. C., P. J. Hunton, C. R. Kovesdi and J. D. Mohon. 2022. “Human Factors Engineering Operating Experience Review of the Constellation Limerick Control Room Upgrade: Results Summary Report.” INL/RPT-22-68703 Idaho National Laboratory.

[4] Kovesdi, C. R. and J. C. Joe. 2022. “Human-System Interface Style Guide for Limerick Generating Station.” INL/RPT-22-68558, Idaho National Laboratory.

[5] NUREG-1764. 2007. “Guidance for the Review of Changes to Human Actions,” Rev 1.

[6] EPRI. 2015. “Human Factors Guidance for Control Room and Digital Human-System Interface Design and Modification: Guidelines for Planning, Specification, Design, Licensing, Implementation, Training, Operation, and Maintenance for Operating Plants and New Builds.” 3002004310.

[7] NUREG/CR-3331. 1983. “A Methodology for Allocation of Nuclear Power Plant Control Functions to Human and Automated Control.” Washington, DC: U.S. Nuclear Regulatory Commission.

[8] IEEE-1023. 2020. “Institute of Electrical and Electronics Engineers Recommended Practice for the Application of Human Factors Engineering to Systems, Equipment, and Facilities of Nuclear Power Generating Stations and Other Nuclear Facilities”

[9] EPRI. 2013. “Human Factors Engineering (HFE) Training Course for Operating Nuclear Power Plant Personnel.” 300200319.

[10] Kovesdi, C. R., Z. A. Spielman, J. D. Mohon, T. M. Miyake, R. A. Hill, and C. Pederson. 2021. “Development of an Assessment Methodology That Enables the Nuclear Industry to Evaluate Adoption of Advanced Automation.” INL/EXT-21-64320, Idaho National Laboratory.

[11] Hunton, P. J., R. T. England, et. al. 2020. “Safety-Related Instrumentation & Control Pilot Upgrade Initial Scoping Phase Implementation Report and Lessons Learned.” INL/EXT-20-59809, Idaho National Laboratory.

[12] Thomas, K D. and P. J. Hunton. 2019. “Nuclear Power Plant Modernization Strategy and Action Plan.” INL/EXT-19-55852, Idaho National Laboratory.

[13] Thomas, K. D., J. Remer, and C. Primer. 2020. “Analysis and Planning Framework for Nuclear Plant Transformation.” INL/EXT-20-59537, Idaho National Laboratory.

[14] 10 CFR 50.62, “Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants.”

[15] Hunton, P. J., R. T. England, P. Heaney, D. Herrell, W. Jessup. 2020. “Vendor-Independent Requirements for a Boiling Water Reactor Safety System Upgrade.” INL/EXT-20-61079, Idaho National Laboratory.

[16] Hunton. P. J. R. T. England, S. Lawrie, W. Jessup, et. al. 2020. “Business Case Analysis for Digital Safety-Related Instrumentation & Control System Modernizations- as Applied to the Limerick Generating Station.” INL/LTD-20-59707, Idaho National Laboratory.

[17] Hunton. P. J. R. T. England, S. Lawrie, W. Jessup, et. al. 2020. “Business Case Analysis for Digital Safety-Related Instrumentation & Control System Modernizations- as Applied to the Limerick Generating Station.” INL/EXT-20-59731, Idaho National Laboratory.

[18] Nuclear Energy Institute (NEI) IP-ENG-001, “Standard Design Process,” Delivering the Nuclear Promise® Initiative.

[19] NEI Nuclear Industry Standard Process – Engineering (NISP-EN-04), “Standard Digital Engineering Process,” Delivering the Nuclear Promise® Initiative.

[20] Electric Power Research Institute. 2018. “Digital Engineering Guide: Decision Making Using Systems Engineering.” Report 3002011816, Electric Power Research Institute.

[21] U.S. Nuclear Regulatory Commission. 2018. “Digital Instrumentation and Controls Licensing Process Interim Staff Guidance,” Revision 2DI&C-ISG-06, Washington, D.C. https://www.nrc.gov/docs/ML1826/ML18269A259.pdf.

[22] “Plant Protection System – System Requirements Specification, Westinghouse Electric Company.” WNA-DS-4899-GLIM (Draft)

[23] “Distributed Process Control System – System Requirements Specification, Westinghouse Electric Company.” WNA-DS-5080-GLIM (Draft)

[24] “Plant Protection System – System Design Specification, Westinghouse Electric Company.” WNA-DS-04900-GLIM (Draft)

[25] “Distributed Process Control System – System Design Specification, Westinghouse Electric Company,” WNA-DS-05079-GLIM (Draft)

[26] Licensing Technical Report for the Limerick Generating Station Units 1&2 Digital Modernization Project.

[27] LTR-AMER-MKG-21-656, Rev. 2, Appendix A.9

[28] Hanes, L., J. Hugo, R. Boring, Ø. Berg, J. Forbes, and M. Gibson. 2013. “Human Factors Operational Experience Review (OER) for Brunswick, Harris and Robinson Plant Process Computer (PPC) and Turbine Control System Upgrades.” INL/LTD-13-2749, Idaho National Laboratory.

[29] Joe, J. C., L. Hettinger, and L. Hanes. 2019. “Human Factors Engineering Operating Experience Review of the Dominion Energy Surry and North Anna Control Room Upgrades: Results Summary Report.” INL/LTD-19-53981, Idaho National Laboratory.

[30] Limerick Generating Station Updated Final Safety Analysis Report (UFSAR), Revision 19, Chapter 15.

[31] “Limerick Defense in Depth and Diversity Common Cause Failure Coping Analysis.” WNA-AR-01074-GLIM, Revision A, Westinghouse Electric Company.

[32] Kovesdi, C. and J. Joe. 2019. “Exploring the Psychometrics of Common Post-Scenario Human Factors Questionnaires of Workload, Situation Awareness, and Perceived Difficulty.” INL/CON-18-45444-Rev000, Idaho National Laboratory.

[33] NUREG/CR-7190. 2015. “Workload, Situation Awareness, and Teamwork.” Washington, D.C. U.S. Nuclear Regulatory Commission.

[34] NUREG-0800. 2016. “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition – Human Factors Engineering.” Revision 3, Chapter 18.

[35] NUREG-1852. 2007. “Demonstrating the Feasibility and Reliability of Operator Manual Actions in Response to Fire.”

[36] NUREG-0700. 2002. "Human-System Interface Design Review Guidelines." Revision 2.

[37] Kovesdi, C., J. Joe, and R. Boring. 2018. "A Guide for Selecting Appropriate Human Factors Methods and Measures in Control Room Modernization Efforts in Nuclear Power Plants." In Proceedings of the International Conference on Applied Human Factors and Ergonomics 441–452. Springer, Cham. https://doi.org/10.1007/978-3-319-94229-2_43.

[38] Estes, S. 2017. "Cogulator." The MITRE Corporation, [Online]. Available: http://cogulator.io.

[39] Regulatory Guide 1.97, "Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants." Revision 2.

[40] AP1000 Design Control Document, Revision 19, Section 18.12, "Inventory," subsection 18.12.2, "Minimum Inventory of Main Control Room Fixed Displays, Alarms, and Controls." https://www.nrc.gov/docs/ML1117/ML11171A390.pdf

[41] LG-PRA-013, Limerick Generating Station Probabilistic Risk Assessment Summary Notebook, Revision 4.

Appendix A

Limerick Generating Station Functional Requirements and Function Allocation Detailed Results

Scenario #1: [ ](C)

Scenario Events Observed
[ ](C)
Task(s) Evaluated
[ ](C)

[

]^(C)

Procedures and Observed Run Time

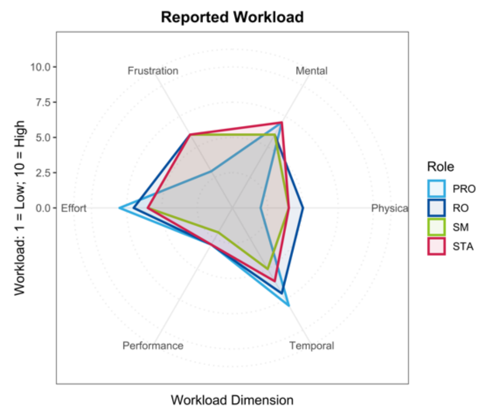
[ ]^(C)

Scenario Results

Self-Report Surveys

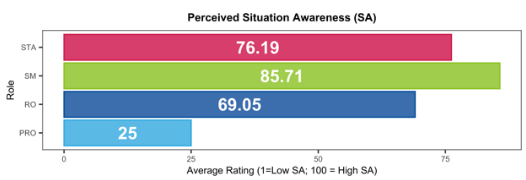
Perceived Workload

NASA-TLX	Single Ease Question	Perceived Demand (Nuclear Usability Measure)
5.25	4.5	4
(1 = Low; 10 = High)	*(1 = Very Difficult; 7 = Very Easy)*	*(1 = Very Demanding; 7 = Very Effortless)*



Perceived Situation Awareness (SA)

SART	Perceived SA (Nuclear Usability Measure)
64	5.25
(1 = Very Low; 100 = Very High)	*(1 = Very Unsuccessful; 7 = Very Successful)*



Observation – SA distribution was noticeably less for the PRO compared to others.

Reported Contributors to Workload and SA

[ ]^(C)

Workload and Situation Awareness Contributors

[ ]^(C)

Subject Matter Expert Review and Observation	
SCORE Ratings	[ ]$^{(C)}$
SME Summary Findings	[ ]$^{(C)}$ **Monitoring** [ ]$^{(C)}$ **Interpretation** [ ]$^{(C)}$ **Strategy** [ ]$^{(C)}$ **Actions** [ ]$^{(C)}$ **Teamwork** [ ]$^{(C)}$ **Control and Verification** [ ]$^{(C)}$

Debrief Results	
Debrief Summary	**Observer 1** [ ](C) **Observer 2** [ ](C)
Allocation of Function	
Proposed Automation	
Applicable Proposed Automated Operator Control Aids	[ ](C)
New Design Feature that Enhance Reliability and Safety	
Design Features	[ ](C)

Scenario #2: [ ]^(C)

Scenario Events Observed

Task(s) Evaluated
[ ]^(C)

Procedures and Observed Run Time

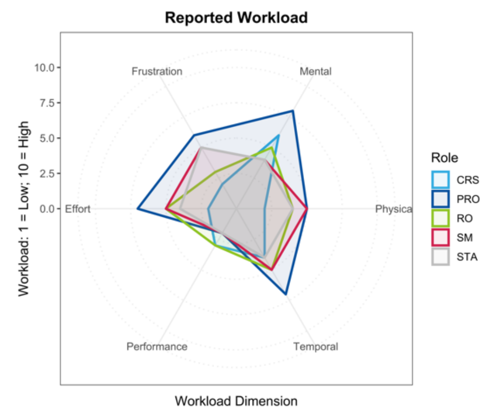
[			](C)

Scenario Results

Self-Report Surveys

Perceived Workload

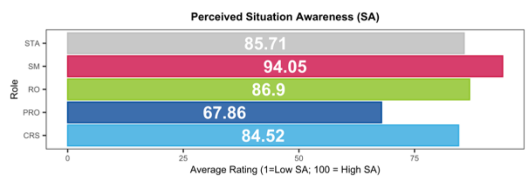
NASA-TLX	Single Ease Question	Perceived Demand (Nuclear Usability Measure)
4.27	6.8	4.8
(1 = Low; 10 = High)	*(1 = Very Difficult; 7 = Very Easy)*	*(1 = Very Demanding; 7 = Very Effortless)*



Observation – Workload distribution was noticeably greater for the PRO compared to others, and especially compared to the CRS.

Perceived Situation Awareness (SA)

SART	Perceived SA (Nuclear Usability Measure)
84	5
(1 = Very Low; 100 = Very High)	*(1 = Very Unsuccessful; 7 = Very Successful)*



Reported Contributors to Workload and SA

[

](C)

Workload and Situation Awareness Contributors

[

](C)

Subject Matter Expert Review and Observation	
SCORE Ratings	[ ]$^{(C)}$
SME Summary Findings	[ ]$^{(C)}$ **Monitoring** [ ]$^{(C)}$ **Interpretation** [ ]$^{(C)}$ **Strategy** [ ]$^{(C)}$ **Actions** [ ]$^{(C)}$ **Teamwork** [ ]$^{(C)}$ **Control and Verification** [ ]$^{(C)}$
Debrief Results	
Debrief Summary	**Observer 1** [ ]$^{(C)}$ **Observer 2** [ ]$^{(C)}$

Allocation of Function	
Proposed Automation	
Applicable Proposed Automated Operator Control Aids	[ ]$^{(C)}$
New Design Feature that Enhance Reliability and Safety	
Design Features	[ ]$^{(C)}$

Scenario #3: [
]$^{(C)}$

Scenario Events Observed
[ ]$^{(C)}$
Task(s) Evaluated
[ ]$^{(C)}$

[

](C)

Procedures and Observed Run Time

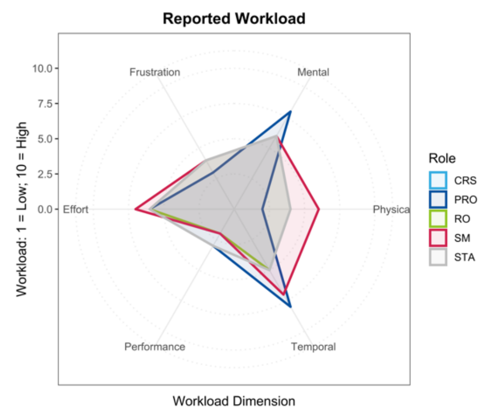
{			](C)

Scenario Results

Self-Report Surveys

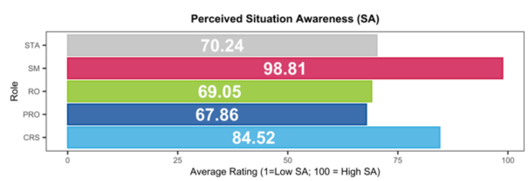
Perceived Workload

NASA-TLX	Single Ease Question	Perceived Demand (Nuclear Usability Measure)
4.8	4.4	3.8
(1 = Low; 10 = High)	*(1 = Very Difficult; 7 = Very Easy)*	*(1 = Very Demanding; 7 = Very Effortless)*



Perceived Situation Awareness (SA)

SART	Perceived SA (Nuclear Usability Measure)
78	6
(1 = Very Low; 100 = Very High)	*(1 = Very Unsuccessful; 7 = Very Successful)*



Reported Contributors to Workload and SA

[

](C)

Workload and Situation Awareness Contributors

[

](C)

Subject Matter Expert Review and Observation	
SCORE Ratings	[ ]^(C)
SME Summary Findings	Performance was overall, **acceptable**. SME evaluation based on the SCORE dimensions above are summarized below. **Monitoring** [ ]^(C) **Interpretation** [ ]^(C) **Strategy** [ ]^(C) **Actions** [ ]^(C) **Teamwork** [ ]^(C) **Control and Verification** [ ]^(C)

Debrief Results	
Debrief Summary	**Observer 1** [ ]$^{(C)}$ **Observer 2** [ ]$^{(C)}$.

Allocation of Function

Proposed Automation	
Applicable Proposed Automated Operator Control Aids	[ ]$^{(C)}$
New Design Feature that Enhance Reliability and Safety	
Design Features	[ ]$^{(C)}$.

Scenario #4: [ ]^(C)

Scenario Events Observed
[ ]^(C)

Task(s) Evaluated
[ ]^(C)

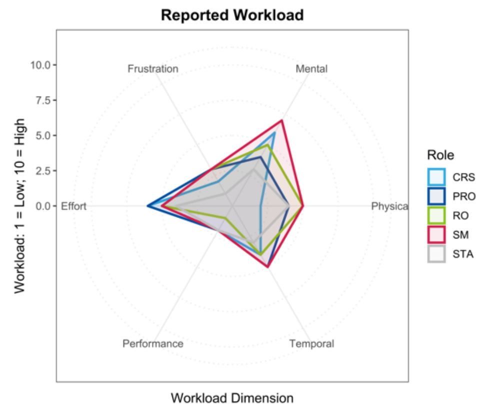
Procedures and Observed Run Time			
[			](C)

Scenario Results

Self-Report Surveys

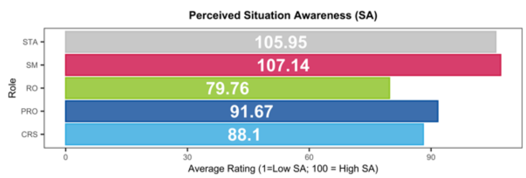
Perceived Workload

NASA-TLX	Single Ease Question	Perceived Demand (Nuclear Usability Measure)
3.77	6.8	5.4
(1 = Low; 10 = High)	*(1 = Very Difficult; 7 = Very Easy)*	*(1 = Very Demanding; 7 = Very Effortless)*



Perceived Situation Awareness (SA)

SART	Perceived SA (Nuclear Usability Measure)
95	5.8
(1 = Very Low; 100 = Very High)	*(1 = Very Unsuccessful; 7 = Very Successful)*



Reported Contributors to Workload and SA	[ ](C)
Workload and Situation Awareness Contributors	[ ](C)

Subject Matter Expert Review and Observation

SCORE Ratings	[ ](C)

SME Summary Findings	[ ](C) **Monitoring** [ ](C) **Interpretation** [ ](C) **Strategy** [ ](C) **Actions** [ ](C) **Teamwork** [ ](C) **Control and Verification** [ ](C)
Debrief Results	
Debrief Summary	**Observer 1** [ ](C) **Observer 2** [ ](C)

Allocation of Function	
Proposed Automation	
Applicable Proposed Automated Operator Control Aids	[ ]$^{(C)}$
New Design Feature that Enhance Reliability and Safety	
Design Features	[ ]$^{(C)}$

Scenario #5: [ ]^(C

Scenario Events Observed
[ ]^(C)

Task(s) Evaluated
[ ]^(C)

Procedures and Observed Run Time

[

](C)

Scenario Results

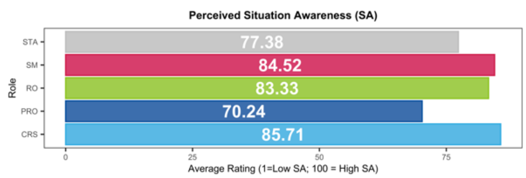
Self-Report Surveys

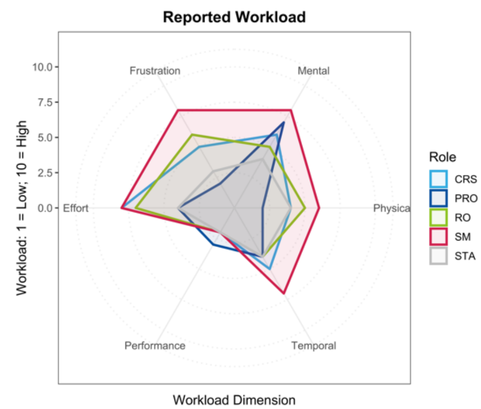
Perceived Workload

NASA-TLX	Single Ease Question	Perceived Demand (Nuclear Usability Measure)
4.7	4.8	4.8
(1 = Low; 10 = High)	*(1 = Very Difficult; 7 = Very Easy)*	*(1 = Very Demanding; 7 = Very Effortless)*

Perceived Situation Awareness (SA)

SART	Perceived SA (Nuclear Usability Measure)
80	5.8
(1 = Very Low; 100 = Very High)	*(1 = Very Unsuccessful; 7 = Very Successful)*





Observation – Workload distribution was noticeably greater for the SM compared to others, and especially compared to the PRO.

Reported Contributors to Workload and SA

[

](C)

Workload and Situation Awareness Contributors

[

](C)

Subject Matter Expert Review and Observation

SCORE Ratings

](C)

SME Summary Findings	Performance was overall, **acceptable**. SME evaluation based on the SCORE dimensions above are summarized below. **Monitoring** [ ](C) **Interpretation** [ ](C) **Strategy** [ ](C) **Actions** [ ](C) **Teamwork** [ ](C) **Control and Verification** [ ](C)
Debrief Results	
Debrief Summary	**Observer 1** [ ](C) **Observer 2** [ ](C)

Allocation of Function	
Proposed Automation	
Applicable Proposed Automated Operator Control Aids	[ ]$^{(C)}$
New Design Feature that Enhance Reliability and Safety	
Design Features	[ ]$^{(C)}$

Scenario #6: [ ](C)

Scenario Events Observed
[ ](C)

Task(s) Evaluated
[ ](C)

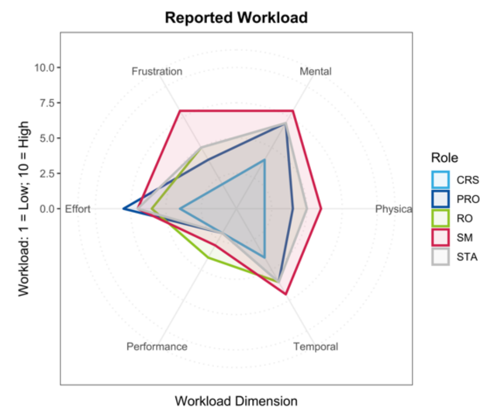
Procedures and Observed Run Time			
[			](C)

Scenario Results

Self-Report Surveys

Perceived Workload

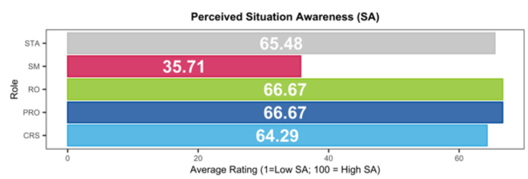
NASA-TLX	Single Ease Question	Perceived Demand (Nuclear Usability Measure)
5.1	5.6	4.2
(1 = Low; 10 = High)	*(1 = Very Difficult; 7 = Very Easy)*	*(1 = Very Demanding; 7 = Very Effortless)*



Observation – Workload distribution was noticeably greater for the SM compared to others, and especially compared to the CRS.

Perceived Situation Awareness (SA)

SART	Perceived SA (Nuclear Usability Measure)
60	5.6
(1 = Very Low; 100 = Very High)	*(1 = Very Unsuccessful; 7 = Very Successful)*



Observation – SA distribution was noticeably less for the SM compared to others.

Reported Contributors to Workload and SA	[ ](C)
Workload and Situation Awareness Contributors	[ ](C)

Subject Matter Expert Review and Observation

SCORE Ratings	[ ](C)

SME Summary Findings	[ ]^(C). **Monitoring** [ ]^(C) **Interpretation** [ ]^(C) **Strategy** [ ]^(C) **Actions** [ ]^(C) **Teamwork** [ ]^(C) **Control and Verification** [ ]^(C)
Debrief Results	
Debrief Summary	**Observer 1** [ ]^(C) **Observer 2** [ ]^(C)
Allocation of Function	
Proposed Automation	
Applicable Proposed Automated Operator Control Aids	[ ]^(C)

New Design Feature that Enhance Reliability and Safety	
Design Features	[ ]$^{(C)}$

Scenario #7: [ ]$^{(C)}$

Scenario Events Observed
[ ]$^{(C)}$

Task(s) Evaluated
[ ]$^{(C)}$

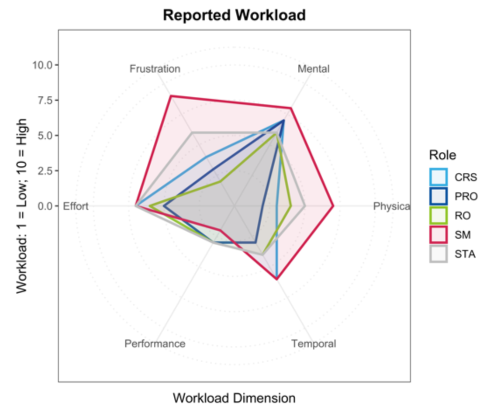
Procedures and Observed Run Time			
[			]^(C)

Scenario Results

Self-Report Surveys

Perceived Workload

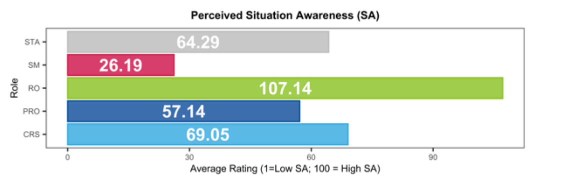
NASA-TLX	Single Ease Question	Perceived Demand (Nuclear Usability Measure)
4.9	4.4	4.6
(1 = Low; 10 = High)	*(1 = Very Difficult; 7 = Very Easy)*	*(1 = Very Demanding; 7 = Very Effortless)*



Observation – Workload distribution was noticeably greater for the SM compared to others.

Perceived Situation Awareness (SA)

SART	Perceived SA (Nuclear Usability Measure)
65	5.4
(1 = Very Low; 100 = Very High)	*(1 = Very Unsuccessful; 7 = Very Successful)*



Observation – SA distribution was noticeably less for the SM; most of the crew reported low SA except for the RO.

Reported Contributors to Workload and SA

[

]^(C)

Workload and Situation Awareness Contributors

[

]^(C)

Subject Matter Expert Review and Observation

SCORE Ratings

]^(C)

SME Summary Findings	[ ](C). **Monitoring** [ ](C). **Interpretation** [ ](C). **Strategy** [ ](C). **Actions** [ ](C). **Teamwork** [ ](C). **Control and Verification** [ ](C).
	Debrief Results
Debrief Summary	**Observer 1** [ ](C). **Observer 2** [ ](C).
Allocation of Function	
	Proposed Automation
Applicable Proposed Automated Operator Control Aids	**Digital HSIs** • Digital HSIs presented at new non-safety (Ovation) and safety (PPS) workstations and large screen VDUs **ADS/ SRVs (Ovation)** • Automatic SRV Pressure Control (Auto-Manual) **HPCI/ RCIC Operations (PPS)** • Level Control with an operator selected RPV level setpoint (Auto-Manual) Semi-automatic Pressure Control (Auto-Manual)

New Design Feature that Enhance Reliability and Safety	
Design Features	[ ]$^{(C)}$.

Scenario #8: [
]$^{(C)}$

Scenario Events Observed
[ ]$^{(C)}$.

Task(s) Evaluated
[ ]$^{(C)}$.

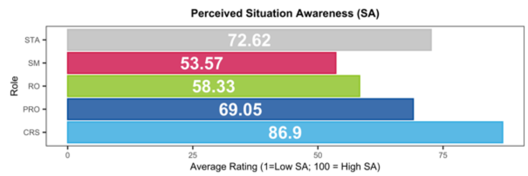
Procedures and Observed Run Time			
[			]$^{(C)}$.

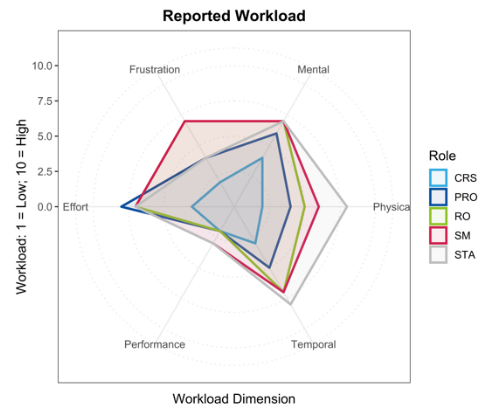
Scenario Results

Self-Report Surveys

Perceived Workload

NASA-TLX	Single Ease Question	Perceived Demand (Nuclear Usability Measure)
5.13	5.4	4.4
(1 = Low; 10 = High)	*(1 = Very Difficult; 7 = Very Easy)*	*(1 = Very Demanding; 7 = Very Effortless)*

<table>
<tr>
<td>Perceived Situation Awareness (SA)</td>
<td>
<table>
<tr><td>SART</td><td>Perceived SA
(Nuclear Usability Measure)</td></tr>
<tr><td>68</td><td>5.6</td></tr>
<tr><td>(1 = Very Low; 100 = Very High)</td><td>(1 = Very Unsuccessful; 7 = Very Successful)</td></tr>
</table>


Observation – SA distribution was noticeably greater for the CRS compared to others.
</td>
<td>


Observation – Workload distribution was noticeably less for the CRS compared to others.
</td>
</tr>
<tr>
<td>Reported Contributors to Workload and SA</td>
<td colspan="2">[

](C).</td>
</tr>
<tr>
<td>Workload and Situation Awareness Contributors</td>
<td colspan="2">[

](C</td>
</tr>
<tr>
<td colspan="3">Subject Matter Expert Review and Observation</td>
</tr>
<tr>
<td>SCORE Ratings</td>
<td colspan="2">[

](C).</td>
</tr>
</table>

SME Summary Findings	Performance was overall, **strongly acceptable**. SME evaluation based on the SCORE dimensions above are summarized below. **Monitoring** [ ](C) **Interpretation** [ ](C) **Strategy** [ ](C) **Actions** [ ](C) **Teamwork** [ ](C) **Control and Verification** [ ](C)

Debrief Results	
Debrief Summary	**Observer 1** [ ]$^{(C)}$ **Observer 2** [ ]$^{(C)}$

Allocation of Function

Proposed Automation	
Applicable Proposed Automated Operator Control Aids	[ ]$^{(C)}$

New Design Feature that Enhance Reliability and Safety	
Design Features	[ ]$^{(C)}$

Scenario #9: [ ](C)

Scenario Events Observed
[ ](C)

Task(s) Evaluated
[ ](C)

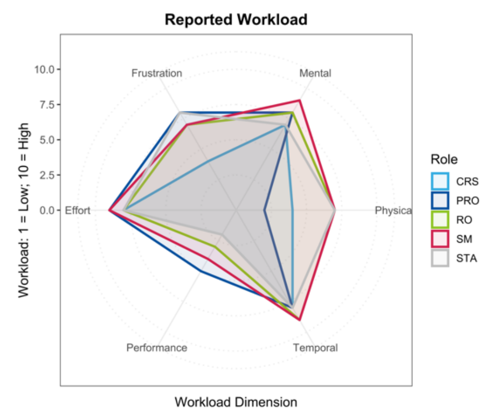
Procedures and Observed Run Time			
[			]^(C)

Scenario Results

Self-Report Surveys

Perceived Workload

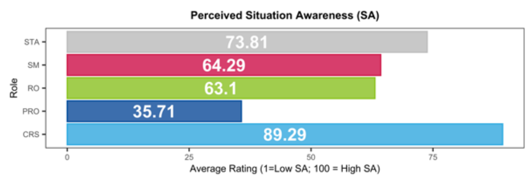
NASA-TLX	Single Ease Question	Perceived Demand (Nuclear Usability Measure)
6.67	3.8	2.2
(1 = Low; 10 = High)	*(1 = Very Difficult; 7 = Very Easy)*	*(1 = Very Demanding; 7 = Very Effortless)*



Observation. Significant workload was observed across the crew.

Perceived Situation Awareness (SA)

SART	Perceived SA (Nuclear Usability Measure)
65	3.36
(1 = Very Low; 100 = Very High)	*(1 = Very Unsuccessful; 7 = Very Successful)*



Observation. SA was noticeably lower for the PRO compared to the rest of the crew.

Reported Contributors to Workload and SA

[ ]^(C)

Workload and Situation Awareness Contributors

[ ]^(C)

Subject Matter Expert Review and Observation

SCORE Ratings

[ ]^(C)

SME Summary Findings	[ ](C) **Monitoring** [ ](C) **Interpretation** [ ](C) **Strategy** [ ](C) . **Actions** [ ](C) **Teamwork** [ ](C) **Control and Verification** [ ](C)
Debrief Results	
Debrief Summary	**Observer 1** [ ](C) **Observer 2** [ ](C)
Allocation of Function	
Proposed Automation	
Applicable Proposed Automated Operator Control Aids	[ ](C)
New Design Feature that Enhance Reliability and Safety	
Design Features	[ ](C)

Appendix B

Limerick Generating Station Task Analysis Detailed Results

[

](C)

Scenario #1: [ ](C)

[

](C)

[

]$^{(C)}$

[

](C)

[

]$^{(C)}$

[

](C)

[

](C)

[

]$^{(C)}$

Scenario #2: [ ](C)

[

](C)

[

]$^{(C)}$

[

](C)

[

]$^{(C)}$

[

](C)

[

](C)

[

]$^{(C)}$

[

](C)

[

]$^{(C)}$

Scenario #3: [ ]$^{(C)}$

[

]$^{(C)}$

[

]^(C)

[

]$^{(C)}$

[

]$^{(C)}$

[

]$^{(C)}$

[

](C)

[

](C)

[

]$^{(C)}$

[

](C)

Scenario #4: [
]$^{(C)}$

[

]$^{(C)}$

[

]$^{(C)}$

[

](C)

Scenario #5: [ ]^(C)

[

]^(C)

[

]^(C)

[

]^(C)

[

]$^{(C)}$

[

](C)

Scenario #6: [ ](C)

[

](C)

[

](C)

[

]$^{(C)}$

[

](C)

[

]$^{(C)}$

[

](C)

[

](C)

Scenario #7: [ ](C)

[

](C)

[

](C)

[

]$^{(C)}$

[

]^(C)

[

](C)

[

]$^{(C)}$

[

]^(C)

Scenario #8: [
]^(C)

[

]^(C)

[

](C)

[

]^(C)

[

](C)

[

]$^{(C)}$

Scenario #9: [ ]$^{(C)}$

[

]$^{(C)}$

Appendix C

Limerick Generating Station Detailed Task Screening List

The following table provides a comprehensive list of all 970 defined tasks performed in the MCR at LGS.

The table columns are defined as follows:

Column	Definition
Task# User ID	Refers to the task ID number as indexed by LGS.
Task	Descriptor of the task.
Crew Average Total	DIF score for the task. A higher number refers to greater combination of difficulty, importance, and frequency.
Training Decision, per NISP-TR-01	Implications for training per DIF score.
Notes	Notes of Training (General)
Chapter 15	Whether the task is referenced in the UFSAR Chapter 15.
In Modification Scope?	Whether the task is impacted from the safety-related upgrades in scope. Yes – Part of the task screening. No
Referenced in D3?	Whether the task is referenced in the D3 analysis, Yes No
Referenced in OER	Operating Experience result item identified in the LGS OER related to a given task (if applicable).
Change in Level of Automation?	Whether the impacted task will be changed such as through migration from existing control boards to either PPS, Ovation, or Both. Yes – (PPS, Ovation, or Both; additional screening) No
Automation: PPS, Ovation, Both, or None	Whether an impacted task will be performed on the PPS, Ovation, or Both.
Controls/Indications Moving Inside MCR	Whether a task that was performed by personnel outside the MCR will be migrated into the MCR and performed by licensed operators.
Applicable Scenario	Scenario identification map. Refers to the SEG number. One or more scenario can be included.
Scenario Task Omission Notes	LGS rationale for exclusion of tasks from scenarios.

The task screening was performed by engineering and operations subject matter experts at LGS. A result of [ ](C) of the [ ](C) tasks were impacted. Of the [ ](C) tasks, [ ](C) were screened into the nine (9) scenarios used to support FRA & FA and TA. Task omission notes are described in 'Scenario Task Omission Notes.' Most omitted tasks were either minimally impacted by the upgrade (e.g., control room abandonment) or were similar in nature to tasks selected.

Non-proprietary document note:

Redaction of proprietary information in the table below has compressed the physical size of the table when compared to the original report. This has reduced the size of the table by a total of 13 pages. To maintain the proper pagination when comparing this non-proprietary version of the report with the original, 13 pages labeled "intentionally left blank" have been added.

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]
[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]	[ ][(C)]

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Task# User ID	Task	Crew Average Total	Training Decision, per NISP-TR-01	Notes	Chapter 15?	In Modification Scope? (Y/N)	Referenced in D3?	Referenced in OER	Change in Level of Automation? (Y/N)	Automation: PPS, Ovation, Both, or None	Controls/Indications Moving Inside MCR	Applicable Scenario	Scenario Task Omission Notes
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)
[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)	[ ](C)

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Page intentionally left blank

Appendix D

Limerick Generating Station Conceptual Displays

Ovation Overview Displays

[

]^(C)

[

]$^{(C)}$

[

]$^{(C)}$

[

]$^{(C)}$

[

][C]

[

]$^{(C)}$

[

](C)

[

]$^{(C)}$

[

]$^{(C)}$

[

]$^{(C)}$

[

]$^{(C)}$

[

](C)

[

](C)

[

]$^{(C)}$

[

]$^{(C)}$

[

](C)

[

]$^{(C)}$

Attachment 8.2

License Amendment Request

Limerick Generating Station, Units 1 and 2

Docket Nos. 50-352 and 50-353

Human Factors Engineering

INL/RPT-22-68995, "Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report," July 2022 (CEG proprietary)

Attachment 9

License Amendment Request

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

Vendor Oversight Plan (VOP) Summary

Limerick Generating Station, Unit 1 and Unit 2
Digital Modernization Project
Vendor Oversight Plan (VOP) Summary, Revision 0

1. Background

Digital Instrumentation & Control (DI&C) Interim Staff Guidance (ISG)-06 (Reference 1), Section C.2.2 describes the licensee prerequisites for use of the Alternate Review Process (ARP). In Section C.2.2.1, DI&C-ISG-06 describes that to use the ARP, the license amendment request (LAR) should provide a description of the licensee's Vendor Oversight Plan (VOP). Section C.2.2.1 states that the LAR should include:

> *A description of the CEG's Vendor Oversight Plan. The plan, when executed, can be used to ensure that the vendor: (1) executes the project consistent with the LAR, and (2) uses an adequate software QA program. The Vendor Oversight Plan, when executed, helps ensure that the vendor will meet both the process and the technical regulatory requirements. Vendor oversight is a series of CEG interactions with the vendor and progresses throughout the entire system development life cycle. The plan should address the intended interactions among the vendor's design, test, verification and validation (V&V), and QA organizations.*

The VOP is an important element of the ARP. Since the LAR approval is requested earlier in the project lifecycle than for the other DI&C-ISG-06 review processes (i.e. Tier 1, 2 or 3), the NRC needs to understand how the licensee intends to ensure that the vendor produces high quality software and system.

Constellation Energy Generation, LLC (CEG) developed a VOP for the Limerick Generating Station (LGS), Unit 1 and Unit 2 Digital Modernization Project to ensure that Westinghouse Electric Company (WEC) executes the project consistent with:

- CEG specification and procurement documents
- The CEG 10 CFR 50 Appendix B Quality Assurance program
- The NRC-approved WEC Software Program Manual (SPM)
- The WEC 10 CFR 50 Appendix B Quality Assurance program

The VOP, which is a subset of the Project Quality Management Program (PQMP) addresses CEG's prerequisites for use of the ARP, as described in Section C.2.2.1 of DI&C-ISG-06, Revision 2. The VOP provides a description of CEG's activities that, when executed, will ensure WEC will meet both process and technical regulatory requirements. The VOP identifies the committed series of interactions between CEG and WEC as the project progresses throughout the entire system development life cycle. The VOP Table of Contents is provided below.

Limerick Generating Station Digital Modernization Project
Vendor Oversight Plan
Table of Contents

2. Vendor Oversight Plan (VOP) Scope

The scope of the VOP addresses the WEC processes and products for the LGS Modernization Project. This includes the hardware, software, design documentation, and licensing documentation provided by WEC. The VOP does not address vendor oversight of the Architect Engineer (A/E) performing the modification process activities. The A/E does not provide any oversight of WEC activities or digital products. The A/E does not perform the DI&C-ISG-06 activities associated with the "vendor." CEG vendor oversight of the A/E is conducted using CEG procedure CC-AA-103-1003, "Owner's Acceptance Review of External Engineering Technical Products."

The purpose of the VOP is to establish an overall approach, including goals, priorities, performance metrics, and resource management strategies for WEC oversight activities. The VOP establishes four strategic objectives through the use of CEG processes and procedures:

1. Verify WEC activities are fulfilling the regulatory obligations through identified WEC inspections with acceptance criteria.
    a. This objective is accomplished by performing WEC inspections that verify the effective implementation of the WEC QA program and activities are conducted in accordance with the Software Program Manual (SPM) and Software Quality Assurance Plan (SQAP).

2. Effectively communicate with internal and external stakeholders.
    a. This objective is accomplished through ensuring the following:
        i. Inspection nonconformances provide sufficient detail to communicate whether WEC is meeting contract and regulatory activities and provide a direct reference to the requirements not met.
        ii. Provide inspection reports that are clear and concise.

3. Perform timely and adequate follow up and closure
    a. Ensure appropriate follow-up activities are identified and assigned owners for remediation of nonconformances and completed in a timely manner consistent with the VOP metrics.

4. Ensure WEC inspectors have the necessary knowledge and skills to successfully validate acceptance criteria.
    a. Vendor inspections shall be conducted by qualified individuals. The CEG process and procedures shall provide additional inspection guidance as required. Additionally, management provides appropriate oversight and review of inspection reports in accordance with CEG process and procedures.

The results of the VOP will assess whether the activities related to the software development coincide with the WEC specified software lifecycle.

Stakeholders identified in VOP Section 1.6, and listed in Section 4 below, will participate in vendor oversight activities to the extent that vendor activities affect their needs. The level of vendor oversight follows a procedure-driven approach, based on the quality processes and procedures described in CEG procedure NO-AA-10, "Quality Assurance Topical Report (QATR)" (Reference 2).

VOP Section 2, "Oversight Guidance and Performance Measures," provides overall guidance for conducting oversight, as well as performance measures during each phase of the software life cycle, while VOP Section 3, "Design Artifacts Verification," identifies specific acceptance criteria for oversight of the WEC design artifacts and programmatic documents.

The CEG Corrective Action Process, which is documented in CEG procedures PI-AA-125, "Corrective Action Process (CAP) Procedure" and PI-AA-120, "Issue Identification and Screening Process," will be used to document and ensure resolution of issues, problems, and non-conformances. This is described in VOP Section 1.3.2 and summarized in Section 7 below. Finally, oversight results will be documented as described in VOP Section 2 and summarized in Section 7 below.

The following key documents provide input to vendor oversight activities:

- CEG Specification NE-402, "Plant Protection System (PPS) Performance Specification" (Reference 3)
- CEG Specification NE-403, "Redundant Reactivity Control System (RRCS) Distributed Control System (DCS) Performance Specification," (Reference 4)
- NRC DI&C-ISG-06 Rev. 2, "Licensing Process"
- WCAP-16096, "Common Qualified Platform Software Program Manual" (Reference 5)
- EPRI Technical Report 3002011816, "Digital Engineering Guide" (DEG) (Reference 6)
- NISP-EN-04, "Standard Digital Engineering Process" (Reference 7)

3. Procedural Basis for VOP

The VOP is an umbrella document covering the range of activities in which CEG is engaged to perform effective vendor oversight. A hierarchy of CEG procedures ensure the effectiveness of vendor quality activities and products. These procedures fall under quality management, procurement, design control, project management, risk management, and corrective action. These procedures, and the role of each in the effective oversight of WEC are described below. In addition, the information below includes a description of the administrative controls that CEG will utilize for any changes to the VOP.

The VOP works in coordination with existing CEG Quality Assurance processes and procedures. This coordination ensures that all vendor documents, software, and equipment meet all quality and design requirements.

<u>Quality Management</u>

NO-AA-10 is the CEG Quality Assurance Topical Report. This document provides a consolidated overview of the quality program controls which govern the operation and maintenance of CEG’s quality related items and activities. The QATR establishes the CEG

10 CFR 50 Appendix B Program and is implemented through the use of approved procedures (e.g., policies, directives, procedures, instructions, or other documents) which provide written guidance for the control of quality related activities and provide for the development of documentation to provide objective evidence of compliance.

For the LGS Digital Modernization project, the main implementing procedures for the QATR are as follows:

- NO-AA-50, "Nuclear Oversight Vendor Audit (NOVA) Process Description"
- NO-AA-210, "Nuclear Oversight Regulatory Audit Procedure"
- NO-AA-500, "Approved Supplier Qualification Activities"
- SM-AA-300, "Procurement Engineering Support Activities"
- SM-AA-300-1004, "Guideline for Specification Development"
- SM-AA-404, "Nuclear Material Procurement"
- SM-AA-405, "Nuclear Contract Services Procurement"
- CC-AA-10, "Configuration Control Process Description"
- CC-AA-103, "Configuration Change Control for Permanent Physical Plant Change"
- CC-AA-103-1003, "Owner’s Acceptance Review of External Engineering Technical Products"
- CC-AA-104, "Document Change Requests"
- CC-AA-107, "Configuration Change Acceptance Testing Criteria"
- CC-AA-107-1002, "Guidelines for Implementing Factory Acceptance Tests"
- CC-AA-254-1000, "Digital Instrumentation and Control Design Guide EPRI 3002002989" (Reference 6)
- NISP-EN-04, "Standard Digital Engineering Process" (Reference 7)
- CC-AA-256, "Process for Managing Plant Modifications Involving Digital Instrumentation & Control Equipment and Systems" (Reference 8)
- CC-AA-605, "Critical Digital Asset (CDA) Hardening per Requirements of 10 CFR 73.54"
- CC-AA-606-1002, "Creating and Maintaining Disaster Recovery Plans for Critical Digital Assets"
- PC-AA-10, "Project Management"
- PC-AA-1005, "Projects Implementation"
- PC-AA-1009, "Project Team Roles & Responsibilities"
- PC-AA-1009-F-1, "Responsibility Assignment Matrix (RAM)"
- PC-AA-1014, "Project Risk Management"
- PC-AA-1017, "Quality Management"
- PC-AA-1018, "Project Scheduling"
- AD-AA-3000, "Nuclear Risk Management Process"
- HU-AA-1212, "Technical Task Risk/Rigor Assessment, Pre-Job Brief, Independent Third-Party Review, and Post-Job Review"
- PI-AA-120, "Issue Identification and Screening Process"
- PI-AA-125, "Corrective Action Program (CAP) Procedure"

NO-AA-50 describes the process for planning, scheduling, preparing, performing, and reporting of vendor audits to verify the effectiveness of a vendor’s quality assurance programs and processes.

NO-AA-210 provides direction for the scheduling, planning, preparing, performing, closing, reporting and following up for Nuclear Oversight (NOS) audits necessary to comply with 10 CFR 50 Appendix B.

NO-AA-500 describes the NUPIC/CEG Audit Process, including elements that are required to be audited to comply with the requirements of 10 CFR 50 Appendix B.

Procurement

SM-AA-404 and SM-AA-405 establish the roles and responsibilities of CEG management personnel in the acquisition of Safety-Related, Augmented Quality, or Non-Safety Related materials and contracted services to support the operations of CEG nuclear facilities.

SM-AA-300 provides requirements for procurement engineering control activities, including inspection and surveillance of vendor activities for the purpose of verifying that an action has been accomplished, as specified, prior to shipment.

SM-AA-300-1004 establishes CEG's method for preparing, commenting, reviewing, approving and issuing technical and quality requirements in procurement specifications, including best practices for the specification of engineering services, materials, and equipment and installation services. Specific to the procurement of digital instrumentation and control equipment and systems, SM-AA-300-1004 invokes CC-AA-256.

Design Control

CC-AA-10 establishes the framework for the interface of design control with other plant processes and identifies sub-tier processes. Sub-tier processes include implementation and review of physical configuration changes, engineering documentation changes (e.g., design analyses, evaluations, and calculations that do not result in physical changes to the station), and acceptance criteria for testing and approval of configuration changes. The purpose of CC-AA-10 is to ensure that changes to the systems, structures or components (SSCs) are in keeping with the design and associated licensing requirements for the facilities.

CC-AA-103, serves as an interface between the industry Standard Design Process procedure, IP-ENG-001 and CEG's supporting design control procedures. IP-ENG-001 establishes the primary configuration change control activities, while CEG-specific supporting activities are described in this procedure, as well as in sub-tier CC-AA procedures.

CC-AA-103-1003 provides guidance on the level of review required for CEG's acceptance of design analyses, technical evaluations, or portions thereof, developed externally by an engineering service provider or other non-CEG entity. Implementation of the guidance in the document provides assurance that the deliverable prepared by an external provider is technically adequate, meets its intended objective, the plant's design and licensing basis, and can be efficiently utilized, including installation, testing, maintenance, and operations of configuration changes.

CC-AA-104 establishes processing requirements for the initiation, engineering review, incorporation and closure of Document Change Requests (DCRs). This process is used, in part, for the approval of a use-as-is disposition for a nonconforming condition.

CC-AA-107 provides the process for the development of testing requirements and acceptance criteria for configuration change packages. Specific to testing requirements for modifying or adding digital electronics and other complex components, the procedure references the EPRI DEG and CC-AA-256 to ascertain the need to implement Integration Testing, Functional Testing, Factory Acceptance Testing (FAT), Site Acceptance Testing (SAT), and if applicable, Site Multiple Vendor Integration Testing.

CC-AA-107 also requires a review of the vendor test plan and the adequacy of the respective vendor test procedures against the functional and the contract requirements using CC-AA-107-1002.

CC-AA-107-1002 provides a guideline for specifying and implementing FATs to ensure the successful installation, commissioning and operation of equipment/systems manufactured and tested by vendors. This guideline applies to FAT test plans prepared by either CEG or the vendor. This guideline also includes information associated with SATs.

For implementation of an engineering-based change involving DI&C equipment and systems, the CC-AA-103 design control process is supplemented with CEG procedure CC-AA-256. CC-AA-256 establishes an interface between CEG DI&C processes and the processes described in the EPRI DEG (i.e., CC-AA-254-1000) (Reference 6) and NISP-EN-04 (Reference 7).

CC-AA-256 addresses:

- Performance of a Digital Design Activity Review to determine the required digital activities
- Establishment of stakeholder engagement in the DI&C change process
- Implementation of DI&C procurement requirements
- Evaluation of potential cyber security concerns
- Review of operational procedures
- Development of a software configuration management plan
- Review of critical configuration parameters
- Validation of as-built configuration and document retention

CC-AA-605 provides a process to determine the applicability of cyber security system hardening controls to a critical digital asset (CDA) classified as a Direct CDA in order to ensure compliance with the requirements in 10 CFR 73.54.

CC-AA-606-1002 provides guidance for restoration of CDA systems, networks, and/or equipment affected by cyber-attacks, or equipment failure after cyber-attacks, including plan exercise and periodic testing.

<u>Project Management</u>

PC-AA-10 provides high-level guidance on the execution of projects. This procedure establishes that the Project Manager is accountable for all aspects of a project and is responsible to manage the project in accordance with the PC-AA series of procedures.
The CEG Project Management Model is a matrixed organization where Functional Area Managers maintain overall authority and responsibility for the individuals and their project-related deliverables. Individuals assigned by the Functional Area Managers are accountable

to the Project Manager for project activities. Both risk management and quality management is interwoven throughout the PC-AA procedures. Specific quality standards are defined in and controlled by the technical, regulatory, and administrative processes, procedures, standards and requirements that support project implementation.

PC-AA-1005 defines actions and deliverables required for projects that are govern3ed by PC-AA-10. It describes sound project management principles and techniques used to plan, monitor, control, execute, and close projects.

PC-AA-1009, in concert with PC-AA-1009-F-1, provides guidance on the establishment of a Project Team within the CEG organization, and specifies the roles and responsibilities for Project Team Members in support of the Project Manager.

PC-AA-1014 provides direction for managing project risks via a structured process. This process provides the structure for the successful project outcome with regards to risk planning, risk identification, risk analysis, risk response; and monitoring and controlling risks. Project-related risks that are considered and evaluated include, but are not limited to safety risks, scope risks, quality risks, financial risks, and schedule risks.

PC-AA-1017 addresses the development of a Project Quality Management Plan (PQMP). The PQMP identifies key elements of Quality Assurance and Quality Control that will be tracked in the plan, in order to identify what will be monitored to ensure a predictable successful outcome of the project. The VOP is incorporated into the PQMP.

PC-AA-1018 provides defines the actions to create and manage project schedules in support of the CEG Project Management Process.

<u>Risk Management</u>

Risk management for the project is implemented through three principal and inter-related procedures: AD-AA-3000, PC-AA-1014, and HU-AA-1212. Graded implementation of the vendor oversight activities described in Section 2 above, as well as development of the Performance Measures and Acceptance Criteria in the VOP, as summarized in Section 5 below, were informed by the guidance in these procedures.

AD-AA-3000 serves as an overarching risk management procedure by providing a consistent method within CEG to evaluate and manage risks and is designed to be used when prompted or required by specific processes. PC-AA-1014 directs the use of the AD-AA-3000 process to evaluate overall project risk and determine the appropriate level of response actions, commensurate with the magnitude and importance of the risk.

HU-AA-1212 provides direction for the risk assessment of technical work; identification of compensating actions; augmented review requirements, including independent third-party reviews (ITPRs); and post-job briefs to capture lessons learned. The HU-AA-1212 risk assessment process evaluates potential consequence risk factors (i.e., an adverse result from performance of a technical task), human performance risk factors, and process risk factors. For every applicable risk factor, the procedure requires identification of compensating actions.

The technical risk assessment process results in an overall risk ranking, which then is used to identify augmented review requirements. Based on HU-AA-1212, the LGS Digital Modernization project risk rank is a 5 or "high" risk. As a result, an independent review is being performed for critical documents.

Corrective Action

PI-AA-125 and PI-AA-120 implement the requirements of Chapter 16 of the QATR (i.e., "Corrective Action"). The Project Management and Engineering Change Processes are part of the CEG Corrective Action Process and therefore are utilized to correct identified conditions, as appropriate

VOP Change Process

As described in VOP Section 1.5, "Revisions to the Vendor Oversight Plan," the VOP is considered a Controlled Document (i.e., CC-AA-4012). All changes to the VOP that are identified require the following actions, prior to implementation:

1. Initiation of an Issue Report (IR) in the CEG corrective action program to track and document the approval, implementation, and communication (i.e., to all stakeholders) of the change.
2. Development and approval of a Training & Reference Material revision in accordance with CEG procedure AD-AA-101, "Processing of Procedures, T&RMs, and Forms."
3. Review of the NRC Safety Evaluation approving the digital upgrade license amendment to ensure that the proposed VOP changes will not adversely impact the basis or requirements for NRC approval.

4. Project Organization and Roles

The following key organizational roles and responsibilities for the project are described in the VOP.

CEG Project Team

Corporate Manager, Project Management
Corporate Sponsor
Project Manager (PM)
Project Facilitator
Supply Management Representative(s)
Site Operations Representative(s)
Lead Responsible Engineer (LRE)
Lead Installation Representative (LIR)
Lead System Representative (LSR)
Training Representative(s)
Information Technology (IT) Representative(s)
Corporate and Site Licensing Representatives

WEC Project Team

Project Manager
Quality Manager
Design Engineers
Cyber Security Engineer
Simulator Project Representative
Test Engineers and Software V&V Engineers
Product Manager
Technical Advisor
Technical Lead
Licensing Lead

5. VOP Structure

Oversight Guidance

Digital I&C safety systems must be designed, fabricated, installed, and tested to quality standards associated with the level of the importance to safety functions to be performed. The safety system shall be developed in accordance with the WEC formally defined life cycle. Section 2 of the VOP provides guidance for conducting oversight during each phase of the WEC design life cycle, as well as performance measures and acceptance criteria associated with each phase:

- Concept Phase
- Requirements Phase
- Design & Implementation Phase
- Implementation Phase
- Testing Phase
- Installation Phase

Vendor oversight activities include:

- Conducting inspections and surveillances
- Reviewing NUPIC audit results
- Conducting Quality Surveillances of vendor activities including activities to validate procurement criteria provided in the purchase specification (i.e., NE-402 and NE-403) References 3 and 4, respectively)
- Providing input to and review/confirmation of specific vendor activities and related information items
- Reviewing vendor design artifacts (e.g., specifications, drawings, analyses)
- Observing or witnessing specific vendor activities
- Participating directly in specific vendor activities
- Coordinating multi-disciplined interactions between various stakeholders
- Communicating status, schedule, and results of oversight activities through daily or weekly CEG/WEC Project Management team teleconferences,

- Conducting CEG/WEC Engineering team teleconferences and CEG/WEC Licensing team teleconferences
- Capturing issues in the CEG and WEC corrective action programs
- Elevating emerging risks and issues (if necessary) to decision makers with higher authority
- Revising the VOP (if necessary) based on emerging results. The project quality management plan that provides the ability to revise the VOP requires that all procedures, references, document inputs, and the Approved SER to be reviewed for any potential impact. Additionally, a review and approval is required by the CEG project manager and engineering manager in accordance with applicable procedures.

Types of Inspections

Vendor inspections are classified as either "Routine" or "Reactive." Routine inspections verify the vendor activities or products are in accordance with the requirements in the CEG specification and WEC SPM. Reactive inspections are conducted in response to allegations, previous inspection nonconformances, or other information indicating the possibility that vendors are not meeting performance requirements. Routine and reactive inspections can be announced or unannounced.

When CEG receives information that questions WEC's ability to provide quality components, the following criteria are used to determine the need to perform a reactive versus a routine inspection:

- Involved loss of a safety function at an operating reactor site where a vendor issue was identified as a root cause
- Involved a major deficiency in design or dedication involving potential generic safety implications
- Led to a significant issue that affected/could affect closure of an inspection report
- Involved a fabrication or construction deficiency involving potential generic implications
- Involved a major deficiency in the design, function, or traceability of a critical digital asset
- Involved repetitive and frequent failures of components or software provided by a specific vendor
- Involved a reported defect that failed to provide an appropriate technical evaluation to address the scope of the identified concern

Section 1.3.1 of the VOP provides an expanded description of the two categories of inspections.

Design Artifacts Verification

A digital system development life cycle provides definition for a deliberate, disciplined, and quality development process. Implementation of the process should result in a high-quality system and supporting software. Verification of the process should confirm, by evaluation against applicable standards and criteria, that vendor procedures and plans are sufficient to accomplish this goal.

The Design Artifacts are the set of design output documents described in the WEC procurement documents. These documents are generated in accordance with the NRC-approved WEC SPM. Examples of design artifacts include the System Requirements Specification (SyRS), System Design Specification (SyDS), and Software Design Specification (SDS).

CEG engineering procedures and processes provide the review framework for these design documents. CC-AA-103-1003 describes the process CEG uses to control the receipt, distribution, review, acceptance, and revision of design analyses, or technical evaluations that are developed externally by an engineering service provider or other non-CEG entity. Implementation of this process provides assurance that the deliverable prepared by an external provider is technically adequate, meets its intended objective, the plant's design and licensing basis, and can be efficiently utilized, including installation, testing, maintenance, and operations of configuration changes. This process:

- Ensures review by appropriate departments and disciplines
- Ensures that affected documents, programs, and data bases are updated
- Ensures that the vendor complies with the design specification and purchase order
- Ensures the document is consistent with plant licensing and design basis
- Ensures technical review is performed based on the risk ranking of the documents.

Performance Measures and Acceptance Criteria

CEG has established inspection guidance and performance measures in VOP Section 2 for each phase of the software life cycle (i.e., with the exception of the *Operation and Maintenance* and *Retirement* phases, since these do not involve the vendor). These Performance Measures are described below. VOP Section 3 provides specific acceptance criteria for each design artifact and WEC programmatic document associated with each phase.

Concept Phase

The Concept Phase consists of basic planning activities to develop project plan documents. These planning documents include management characteristics, implementation characteristics, and resource characteristics. CEG inspection activities will validate, for each plan document, that:

- Management characteristics include a stated Purpose, identify Organizational and Oversight responsibilities, and account for risk and security management.
- Implementation characteristics include Process Metrics as well as guidance on Procedure Control and Recordkeeping.
- Resource characteristics shall include details of Special Tools utilized in the development process, personnel resources and qualification, and the standards used to meet regulatory requirements.

Requirements Phase

The Requirements Phase consists of developing a description of what the software/DI&C system must accomplish. CEG inspection and surveillance activities will verify:

- Software design requirements are documented and incorporate applicable regulatory requirements, standards, and codes.
- Requirements documentation specifies the operating system, functionality, performance characteristics, interfaces, installations considerations, design constraints, and security constraints.
- A formal process is documented and implemented to ensure changes to software requirements are evaluated, reviewed, approved, and documented.
- Implementation of controls for traceability, for a select sample of requirements.

Design Phase

The design phase consists of translating requirements into a hardware/software architecture. CEG inspections will assess and verify that:

- Procedures are implemented to ensure design requirement documentation is reviewed, approved, baselined, updated as necessary, and placed under configuration control.
- A process is implemented to establish a software baseline at the completion of each design activity.
- Procedures are implemented to ensure that changes made to the software are evaluated, reviewed, approved, and documented.

Implementation and Coding Phase

The implementation phase consists of translating the completed software design into code. CEG inspections and surveillances will assess the implementation activities to verify that:

- Implementation activities, such as the creation of an executable code, development of operation documentation, software unit testing, and management of software releases are completed in accordance with a documented implementation plan.

- Procedures are established and implemented for compliance with coding rules, methods, and standards.

Integration, Test, and V&V Phase

The integration phase consists of combining software components and hardware components into a single system. CEG inspections and surveillances will assess the integration and test activities will verify that:

- Plans and methods for integrating function divisions of software (units) are adequately documented, including a schedule, resource and staffing estimates, and criteria for the commencement of software integration.
- Procedures ensure the complete integration of all software units and comprised software modules or any other division of functional parts.
- Software integration test activities and tasks; primary test methods and standards; test cases; test coverage; and acceptance criteria are documented.

The software testing phase consists of unit testing, integration testing, validation testing, and installation (acceptance) testing. For DI&C systems, this includes software testing, software integration testing, software qualification testing, system integration testing, and system qualification testing. CEG inspections will assess and verify that:

- Provisions are documented in procedures to ensure that all software requirements are covered by acceptance testing.
- Documentation supporting software testing includes the following:
    - Qualifications, duties, responsibilities, and skills required of persons and organizations assigned to testing activities
    - Special conditions and controls, equipment, tools, and instrumentation needed for the accomplishment of testing
    - Test instructions and procedures that incorporate the requirements and acceptance limits in applicable design documents
    - Test prerequisites and the criteria for meeting these requirements and acceptance limits
    - Test items and the approach taken by the testing program
    - Test logs, test data, and test results
    - Acceptance criteria
    - Test records that indicate the identity of the tester, the type of observation made, the results and acceptability, and the action taken in connection with any deficiencies
- Test plans, test activities and task, test cases, and test coverage test methods and standards
- Test results are documented, reviewed, analyzed, and approved, by a qualified individual to ensure test requirements have been fulfilled.
- A method to identify and resolve discrepancies between actual and expected integration test results is documented.
- Adequacy of the process to incorporate software changes due to test results, in order to ensure that all test anomalies are documented and resolved.

- Actions taken to address testing anomalies include revision to system and software requirement documentation and subsequent design documentation as necessary.
- DI&C system testing is conducted on a completely integrated system, in which all hardware and software functionality has successfully passed integration testing and have been combined into one final system.

CEG inspections of V&V activities will verify that procedures are established and effectively implemented for:

- Performing design reviews, alternate calculations, or testing to verify the adequacy of the software design.
- Conducting management reviews, technical reviews, inspections, walkthroughs, and audits.
- Documenting and resolving all non-conformances identified during the software development lifecycle.
- Identifying problems, extent of condition, and risk mitigation actions for issues that have the potential to significantly impact the system quality.
- Conducting reviews which ensure conformance of the software to design requirements and satisfactory completion of the software development activities/phases.

Installation and Checkout Phase

The installation phase consists of installing and testing the software in its operational environment. CEG inspections of the system testing activities will verify that procedures are established and effectively implemented for:

- Documenting modifications to the software made during installation.
- Performing acceptance testing to demonstrate the installed system will perform its intended safety function as described in the system design basis.
- Documenting acceptance test activities and tasks; primary test methods and standards; test cases; test coverage; and acceptance criteria.
- Documenting and resolving conditions that deviate from expectations based on requirements specifications, design documents, user documents, or standards prior to placing the system into operation.

6. Plant Specific Action Items (PSAIs)

In addition to the phase-based inspection activity and design artifact verification, as described above, CEG will ensure that the PSAIs that are identified in the WEC platform Topical Reports, and further discussed in WCAP-18598-P, "Licensing Technical Report for the Limerick Generating Station Plant Protection System," (non-proprietary and proprietary versions were previously submitted, in support of this license amendment request: ADAMS Accession Nos. ML22231A179 and ML22231A180, respectively), are addressed, as described in the LAR.

7. Corrective Actions and Documentation

CEG will use the Corrective Action Process described in procedures PI-AA-120 and PI-AA-125 to screen, investigate, determine corrective actions, and report all non-conformances and discrepancies identified by vendor oversight activities.

Non-conformances can include instances where the equipment or system (1) does not meet the physical/functional requirements and specifications (e.g., hardware, software, wiring, etc.) due to vendor related errors, (2) performs differently than desired, resulting in a change to design drawings/documents and/or procedures, or (3) was physically or functionally changed (e.g. hardware, software, wiring, etc.) during the FAT, at the request of the design team.

A standard Inspection Report Template (i.e., Attachment A to the VOP) will be used to document and disposition non-conformances found during the vendor oversight process. All Inspection Reports will be documented in CAP:

- When operational and performance anomalies are identified that could impact any of the design drawings/documents and/or procedures, a unique Issue Report (IR) will be generated in CAP to document and investigate the discrepancy.
- For all other incomplete work and non-conformance test exceptions, one IR that includes all issues may be used.

Each non-conformance and testing issue will be categorized according to the type of resolution:

- Resolved on the spot. In this case, design/construction/testing is allowed to continue after resolution
- On-going resolution during the process
- Inspection repeated following resolution
- Modification required after the FAT, before the system is shipped

CEG will implement an Inspection Report issue tracking matrix to identify and track the status of all open items related to the equipment design, fabrication and testing and their planned resolutions to:

- Ensure the changes necessary for the equipment/system to perform the specified functions are made in a permanent manner and retested, including regression testing, before completion of activities. This applies to the associated design process, as well. For example, a design change required during testing could impact the conclusions of the Failure Modes and Effects Analysis (FMEA), requiring further evaluation and potential changes to testing methods/acceptance criteria. Implementing changes in a permanent manner will minimize the potential for invalidating critical design documents and/or testing, inadvertently.
- Ensure all changes to approved design drawings/documents are reviewed and approved by CEG using the same process that was used for the review and approval of the prior revisions.

8. References

1. NRC DI&C-ISG-06 Rev. 2, "Licensing Process"
2. NO-AA-10, "Quality Assurance Topical Report (QATR)"
3. CEG Specification NE-402, "Plant Protection System (PPS) Performance Specification"
4. CEG Specification NE-403, "Redundant Reactivity Control System (RRCS) Distributed Control System (DCS) Performance Specification"
5. WCAP-16096, "Common Qualified Platform Software Program Manual"
6. EPRI Technical Report 3002011816, "Digital Engineering Guide" (DEG)
7. NISP-EN-04, "Standard Digital Engineering Process"
8. CC-AA-256, "Process for Managing Plant Modifications Involving Digital Instrumentation & Control Equipment and Systems"

Attachment 10

License Amendment Request

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

Regulatory Commitment

Attachment 10

License Amendment Request

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

Regulatory Commitment

The following table identifies the regulatory commitment in this license amendment request. Any other statements in this submittal represent intended or planned actions. They are provided for information purposes and are not considered to be regulatory commitments.

Commitment	Type		Scheduled Completion Date
	One-Time Action	Continuing Compliance	
Constellation Energy Generation, LLC will evaluate the Limerick Generating Station Digital Modernization Project Site Acceptance Test (SAT) and Installation Test Plans using the software process testing characteristics described in BTP 7-14, Section B.3.2.4. This is Plant-specific Action Item #5 per WCAP-16097, *Common Qualified Platform Topical Report.*	√		

Enclosure 2

License Amendment Request Supplement

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

Affidavit for Attachment 8.2 of Enclosure 1

Constellation Energy Generation, LLC

AFFIDAVIT

State of Illinois:

County of DuPage:

(1) I, David Gullott, Director-Licensing, have been specifically delegated and authorized to apply for withholding and execute this Affidavit on behalf of Constellation Energy Company, LLC (CEG).

(2) I am requesting the proprietary portions of INL/RPT-22-68995, "Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report," July 2022," be withheld from public disclosure under 10 CFR 2.390.

(3) I have personal knowledge of the criteria and procedures utilized by CEG in designating information as a trade secret, privileged, or as confidential commercial or financial information.

(4) Pursuant to 10 CFR 2.390, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld:

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by CEG and is not customarily disclosed to the public.

(ii) The information sought to be withheld is being transmitted to the Commission in confidence and, to CEG knowledge, is not available in public sources.

(iii) CEG notes that a showing of substantial harm is no longer an applicable criterion for analyzing whether a document should be withheld from public disclosure. Nevertheless, public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of CEG because it would enhance the ability of competitors to provide similar technical evaluation justifications and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

(5) CEG has policies in place to identify proprietary information. Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of CEG's competitors without license from CEG constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage (e.g., by optimization or improved marketability).

(c) Its use by a competitor would reduce their expenditure of resources or improve their competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of CEG, its customers or suppliers.

(e) It reveals aspects of past, present, or future CEG or customer funded development plans and programs of potential commercial value to CEG.

(f) It contains patentable ideas, for which patent protection may be desirable.

(6) The attached document is bracketed, [ ](C), and marked to indicate redacted proprietary information. The bases for withholding falls under 5(a) and/or 5(b) discussed above.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 29th day of August 2023.

Signed electronically by: Gullott, David M. Digitally signed by Gullott, David M. Date: 2023.08.29 15:04:27 -05'00' ____________________________