FPL

April 9, 2014
L-2014-033
10 CFR 50.90

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555-0001

Re: Turkey Point Nuclear Plant, Units 3 and 4
Docket Nos. 50-250 and 50-251
Renewed Facility Operating Licenses DRR-31 and DPR-41

License Amendment Request No. LAR-229
Application for Technical Specification Change Regarding Risk-Informed Justifications for the Relocation of Specific Surveillance Frequency Requirements to a Licensee Controlled Program

Pursuant to 10 CFR Part 50.90, Florida Power and Light Company (FPL) is submitting a request for an amendment to the Renewed Facility Operating Licenses DPR-31 and DPR-41 for Turkey Point Nuclear Plant (Turkey Point) Units 3 and 4, respectively. The proposed amendment would modify the Turkey Point Technical Specifications (TS) by relocating specific surveillance frequencies to a licensee-controlled program with implementation of Nuclear Energy Institute (NEI) 04-10, "Risk-Informed Technical Specification Initiative 5b, Risk Informed Method for Control of Surveillance Frequencies," (ADAMS Accession No. ML071360456).

The changes are consistent with NRC-approved Technical Specifications Task Force (TSTF) Standard Technical Specifications (STS) change TSTF-425, "Relocate Surveillance Frequencies to Licensee Control – Risk Informed Technical Specifications Task Force (RITSTF) Initiative 5b," Revision 3, (ADAMS Accession No. ML090850642). Federal Register "Notice of Availability of Technical Specification Improvement to Relocate Surveillance Frequencies to Licensee Control – Risk Informed Specification Task Force (RITSTF) Initiative 5b, Technical Specification Task Force - 425, Revision 3," published on July 6, 2009 (74 FR 31996) announced the availability of this TS improvement.

Attachment 1 provides a description of the proposed changes, the requested confirmation of applicability, and plant-specific verifications. Attachment 2 provides documentation of probabilistic risk assessment (PRA) technical adequacy. Attachment 3 provides the existing TS pages marked-up to show the proposed changes, and Attachment 4 provides the proposed TS Bases changes. The changes to the TS Bases are provided for information only and will be incorporated in accordance with the TS Bases Control Program upon implementation of the approved amendment. Attachment 5 contains the Proposed No Significant Hazards Consideration Determination. Attachment 6 provides a cross-reference between the surveillance requirements (SR) contained in TSTF-425 and the SR in the Turkey Point TS.



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Please process these changes within one (1) year of receipt, and once approved, the amendments will be implemented within 90 days. This letter contains no new commitments and no revisions to existing commitments.

These changes have been reviewed by the Turkey Point Plant Nuclear Safety Committee. Pursuant to 10 CFR 50.91(b)(1), a copy of this submittal is being forwarded to the designated State of Florida official.

Should you have any questions regarding this submittal, please contact Mr. Robert J. Tomonto, Licensing Manager, at (305) 246-7327.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on the ninth day of April 2014.

Very truly yours,

Michael Kiley
Site Vice President
Turkey Point Nuclear Plant

Attachments (6)

cc: USNRC Regional Administrator, Region II
USNRC Project Manager, Turkey Point Nuclear Plant
USNRC Senior Resident Inspector, Turkey Point Nuclear Plant
Ms Cindy Becker, Florida Department of Health

# Attachment 1

# Turkey Point Nuclear Plant

# Description and Assessment
# License Amendment Request No. LAR-229

Subject: Application for Technical Specification Change Request Regarding Risk-Informed Justifications for the Relocation of Specific Surveillance Frequency Requirements to a Licensee Controlled Program

## 1.0 DESCRIPTION

The proposed amendment would modify the Turkey Point Nuclear Plant (Turkey Point), Units 3 and 4 Technical Specifications (TS) by relocating specific surveillance frequencies to a licensee-controlled program with the adoption of Technical Specification Task Force (TSFT)-425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control – Risk Informed Technical Specification Task Force (RITSTF) Initiative 5b" [Reference 1]. Additionally, the change would add a new program, the Surveillance Frequency Control Program (SFCP) to TS Section 6.0, Administrative Controls, Subsection 6.8, Procedures and Programs. The changes are consistent with NRC approved industry / TSTF Standard Technical Specifications (STS) change TSTF-425, Revision 3. Federal Register "Notice of Availability of Technical Specification Improvement to Relocate Surveillance Frequencies to Licensee Control – Risk Informed Specification Task Force (RITSTF) Initiative 5b, Technical Specification Task Force - 425, Revision 3," published on July 6, 2009 (74 FR 31996) [Reference 2] announced the availability of this TS improvement.

## 2.0 ASSESSMENT

### 2.1 Applicability of Published Safety Evaluation

Florida Power and Light Company (FPL) has reviewed the safety evaluation dated July 6, 2009. The review included a review of the NRC staff's evaluation, TSTF-425, Revision 3, and the requirements specified in Nuclear Energy Institute (NEI) 04-10, Revision 1 "Risk-Informed Method for Control of Surveillance Frequencies," [Reference 3].

Attachment 2 includes FPL's documentation with regard to PRA technical adequacy consistent with the requirements of Regulatory Guide (RG) 1.200, Revision 1, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results in Risk-Informed Activities," [Reference 4], Section 4.2, and describes any Probabilistic Risk Assessment (PRA) models without NRC-endorsed standards, including documentation of the quality characteristics of those models in accordance with RG 1.200.

FPL has concluded that the justifications presented in the TSTF proposal and the safety evaluation prepared by the NRC staff are applicable to Turkey Point Units 3 and 4 and justify this amendment to incorporate the changes to the Turkey Point TS.

### 2.2 Optional Changes and Variations

The proposed amendment is consistent with STS changes described in TSTF-425, Revision 3, but FPL proposes variations or deviations from TSTF-425, as described below:

1. Revised (clean) TS pages are not included in this amendment request given the number of TS pages affected, the straightforward nature of the proposed changes, and outstanding license amendment requests that may affect some of the same TS pages. Providing only mark-ups of the proposed TS changes satisfies the requirements of 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," in that the mark-ups fully describe the changes desired.

This is an administrative deviation from the NRC staff's model application dated July 6, 2009 (74 FR 31996) with no impact on the NRC staff's model safety evaluation published in the same Federal Register Notice. As a result of this deviation, the contents and numbering of the attachments for this amendment request differ from the attachments specified in the NRC staff's model application.

2. The Turkey Point TS were based on the standard TS at the time they were issued. As a result, the Turkey Point TS surveillance numbers and associated Bases numbers differ from the surveillance numbers and Bases numbers in NUREG-1431, "Standard Technical Specifications – Westinghouse Plants," Revision 4, Volumes 1 and 2 [Reference 5] and TSTF-425, Revision 3. In addition, the Administrative Controls Section TS is Section 6.0 for Turkey Point verses Section 5.0 for NUREG-1431. These differences are administrative deviations from TSTF-425 with no impact on the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996).

   There are surveillances contained in NUREG-1431 that are not contained in the Turkey Point TS. These surveillances identified in TSTF-425 for NUREG-1431 are not applicable to Turkey Point. This is an administrative deviation from TSTF-425 with no impact on the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996).

3. The Turkey Point TS include plant-specific surveillances that are not contained in NUREG-1431 and, therefore are not included in the NUREG-1431 surveillances provided in TSTF-425. FPL has determined that the relocation of the frequencies for these Turkey Point specific surveillances is consistent with TSTF-425, Revision 3, and with the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996), including the scope exclusions identified in Section 1.0, "Introduction," of the model safety evaluation, because the plant-specific surveillance frequencies involve fixed period frequencies. Changes to the frequencies for these plant-specific surveillances would be controlled under the SFCP.

   The SFCP provides the necessary administrative controls to require that surveillances related to testing, calibration, and inspection are conducted at a frequency to assure that the necessary quality of the systems and components is maintained, the facility operation will be within safety limits, and that the Limiting Conditions for Operation will be met. Changes to frequencies in the SFCP would be evaluated using the methodology and probabilistic risk guidelines contained in NEI 04-10, Revision 1, "Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method of Control of Surveillance Frequencies," as approved by NRC letter "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) 04-10, Revision 1, "Risk Informed Technical Specification Initiative 5b, "Risk-Informed Method for Control of Surveillance Frequencies(TAC No. MD6111)," dated September 19, 2007 [Reference 6].

   The NEI 04-10, Revision 1 methodology includes qualitative considerations, risk analyses, sensitivity studies and bounding analyses, as necessary, and recommended monitoring of the performance of systems, structures, and components (SSCs) for which frequencies are changed to assure that reduced testing does not adversely impact the SSCs. The NEI 04-10 Revision 1 methodology

satisfies the five key safety principles specified in RG 1.177, "An Approach for Plant-Specific Risk-Informed Decision Making: Technical Specifications," dated August 1998 [Reference 7], relative to changes in surveillance frequencies. Therefore, the proposed relocation of the Turkey Point-specific surveillance frequencies is consistent with TSTF-425 and with the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996).

4. The definition of STAGGERED TEST BASIS is being retained in the Turkey Point TS Definition Section 1.0 since the terminology is being maintained in TS Surveillance Requirements in Sections 3/4.3, Instrumentation, 3/4.7, Plant Systems, and 3/4.8, Electrical Power Systems. In addition, the terminology is used in Section 6.8.4.k, "Control Room Envelop Habitability Program," which is not the subject of this amendment request and is not proposed to be changed. This is an administrative deviation from TSTF-425 with no impact on the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996).

5. The insert provided in TSTF-425 for the TS Bases (Insert 2) states "The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program." In a letter dated April 14, 2010 [Reference 8], the NRC staff agreed that the insert applies to surveillance frequencies that are relocated and subsequently evaluated and changed in accordance with the SFCP, but does not apply to frequencies relocated to the SFCP, but not changed. Therefore, the insert for the Bases is revised to "The Surveillance Frequency is controlled under the Surveillance Frequency Control Program." This is an administrative deviation from TSTF-425 with no impact on the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996).

6. The Turkey Point TS were based on the standard TS at the time they were issued which did not contain Bases as comprehensive as those in NUREG-1431. Therefore, many of the Bases mark-ups in TSTF-425 are not applicable to the Turkey Point TS. The proposed Bases changes in Attachment 4 revise only those Bases that currently discuss surveillance frequencies. This is an administrative deviation from TSTF-425 with no impact on the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996). The existing Bases information describing the basis for the surveillance frequencies will be relocated to the Turkey Point SFCP.

7. The SR for the Reactor Trip System Instrumentation and Engineered Safety Features Actuation System Instrumentation in Turkey Point TS 3.3.1 and 3.3.2 are presented in tabular format, which is different from the format of the SR for the same instrumentation in NUREG-1431. To accommodate this difference, the proposed changes includes use of "SFCP" as a frequency notation in the tables that specify instrumentation SR. This is an administrative deviation from TSTF-425 due to differences in format between Turkey Point TS and NUREG-1431, which has no impact on the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996).

8. TS Table 3.3-4, Action Statements, Action 27 is being revised to change "expect" to "except" and TS 3.7.1.2 is being revised to change "APPLICA8ILITY" to "APPLICABILITY". These differences from TSTF-425 are editorial changes to correct existing typographical errors and have no impact on the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996).

## 3.0 REGULATORY ANALYSIS

### 3.1 No Significant Hazards Consideration

FPL has reviewed the proposed no significant hazards consideration (NSHC) determination published in the Federal Register July 6, 2009 (74 FR 31996). FPL has concluded that the proposed NSHC presented in the Federal Register notice is applicable to Turkey Point and is provided as Attachment 5 to this amendment request which satisfies the requirements of 10 CFR 50.91(a).

### 3.2 Applicable Regulatory Requirements / Criteria

A description of the proposed changes and their relationship to applicable regulatory requirement is provided in TSTF-425, Revision 3 (ADAMS Accession No. ML090850642) and the NRC staff's model safety evaluation published in the Federal Register is applicable to Turkey Point.

### 3.3 Conclusions

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

## 4.0 ENVIRONMENTAL CONSIDERATION

FPL reviewed the environmental consideration included in the NRC staff's model safety evaluation published in the Federal Register on July 6, 2009 (74 FR 31996). FPL concluded that the NRC staff's findings presented therein are applicable to Turkey Point and the determination is hereby incorporated by reference to this application.

The proposed change does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed change meets 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 change.

## 5.0 REFERENCES

1. Technical Specification Task Force (TSTF)-425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control – RITSTF Initiative 5b," March 18, 2009 (ADAMS Accession No. ML090850642).

2. Notice of Availability of Technical Specification Improvement to Relocate Surveillance Frequencies to Licensee Control – Risk-Informed Technical Specification Task Force (RITSTF) Initiative 5b, Technical Specification Task Force (TSTF)-425, Revision 3, July 6, 2009 (74 FR 31966).

3. Nuclear Energy Institute (NEI) 04-10, Revision 1, "Risk-Informed Method for Control of Surveillance Frequencies," April 2007 (ADAMS Accession No. ML071360456).

4. Regulatory Guide (RG) 1.200, Revision 1, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results in Risk-Informed Activities," Revision 1, January 2007 (ADAMS Accession No. ML070240001).

5. NUREG-1431, "Standard Technical Specifications - Westinghouse Plants," Revision 4, Volumes 1 and 2, April 30, 2012, (ADAMS Accession Nos. ML12100A222 and ML12100A228).

6. H. K. Niedh (NRC) letter to B. Bradley (NE), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) 04-10, Revision 1, "Risk-Informed Technical Specification Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies" (TAC No. MD6111), September 19, 2007, (ADAMS Accession No. ML072570267)

7. Regulatory Guide (RG) 1.177, "An Approach for Plant-Specific, Risk Informed Decision-Making: Technical Specifications," August 1998 (ADAMS Accession No. ML003740176).

8. NRC letter to Technical Specifications Task Force, "Notification of Issue with NRC-Approved Technical Specifications Task Force (TSTF) Traveler TSTF-425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control – RITSTF Imitative 5b," April 14, 2010 (ADAMS Accession No. ML100990099).

# Attachment 2

# Turkey Point Nuclear Plant
# License Amendment Request No. LAR-229

# Documentation of Probabilistic Risk Assessment (PRA) Technical Adequacy

**This coversheet plus 65 pages.**

# Documentation of PRA Technical Adequacy

## Table of Contents

## 1.0 INTRODUCTION

The implementation of the Surveillance Frequency Control Program (SFCP, also referred to as Technical Specifications Initiative 5b) at Turkey Point Station will follow the guidance provided in NEI 04-10, Revision 1 [Reference 1] in evaluating proposed surveillance test interval (STI) changes. The following steps of the risk-informed STI revision process are common to all proposed STI changes within the proposed licensee controlled program.

- Each proposed STI revision is reviewed to determine whether there are any commitments made to the NRC that may prohibit changing the interval. If there are no related commitments, or the commitments may be changed using a commitment change process based on NRC-endorsed guidance, then evaluation of the STI revision can proceed. If a commitment exists, and the commitment change process does not permit the change without NRC approval, then the STI revision cannot be implemented. Only after receiving NRC approval to change the commitment could a STI revision proceed.
- A qualitative analysis is performed for each STI revision that involves several considerations as explained in NEI 04-10, Revision 1.
- Each STI revision is reviewed by an expert panel, referred to as the Integrated Decision-making Panel (IDP), which is normally the same panel used for Maintenance Rule implementation, but with the addition of specialists with experience in surveillance tests and system or component reliability. If the IDP approves the STI revision, the change is documented, implemented, and available for future audits by the NRC. If the IDP does not approve the STI revision, the STI value is left unchanged.
- Performance monitoring is conducted as recommended by the IDP. In some cases, no additional monitoring may be necessary beyond that already conducted under the Maintenance Rule. Performance monitoring helps to confirm that no failure mechanisms related to the revised test interval are subsequently identified as sufficiently significant to alter the basis provided in the justification for the surveillance interval change.
- The IDP is responsible for periodic review of performance monitoring results. If it is determined that the time interval between successive performances of a surveillance test is a factor in the unsatisfactory performances of the surveillance, the IDP returns the STI back to the previously acceptable STI.
- In addition to the above steps, the Probabilistic Risk Assessment (PRA) is used, when possible, to quantify the effect of a proposed individual STI revision compared to acceptance criteria in NEI 04-10, Revision 1. Also, the cumulative impact of risk-informed STI revisions on PRA evaluations (i.e., internal events, external events, and shutdown) is compared to the risk acceptance criteria as delineated in NEI 04-10, Revision 1. For those cases where the STI cannot be modeled in the plant PRA (or where a particular PRA model does not exist for a given hazard group), a qualitative or bounding analysis is performed to provide justification for the acceptability of the proposed test interval change.

The NEI 04-10, Revision 1 methodology endorses the guidance provided in Regulatory Guide (RG) 1.200, Revision 1, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities." The guidance in RG

1.200 indicates that the following steps should be followed when performing PRA assessments:

1. Identify the parts of the PRA used to support the application.
   - Identify structures, systems, and components (SSCs), and operational characteristics that are affected by the application and how these are implemented in the PRA model.
   - A definition of the acceptance criteria used for the application.
2. Identify the scope of risk contributors addressed by the PRA model.
   - If not full scope (i.e., internal events, external events, applicable modes), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the PRA model.
3. Summarize the risk assessment methodology used to assess the risk of the application.
   - Include how the PRA model was modified to appropriately model the risk impact of the change request.
4. Demonstrate the technical adequacy of the PRA.
   - Identify plant changes (design or operational practices) that have been incorporated at the site, but are not yet in the PRA model and justify why the change does not impact the PRA results used to support the application.
   - Document peer review findings and observations that are applicable to the parts of the PRA required for the application, and for those that have not yet been addressed, justify why the significant contributors would not be impacted.
   - Document that the parts of the PRA used in the decision are consistent with applicable standards endorsed by the RG (currently, RG 1.200, Revision 1, which includes only the internal events PRA standard). Provide justification to show that where specific requirements in the standard are not adequately met, it will not unduly impact the results.
   - Identify key assumptions and approximations relevant to the results used in the decision-making process.

Because of the broad scope of potential Initiative 5b applications and the fact that the impact of such assumptions differs from application to application, each of the issues encompassed in Items 1 through 3 will be covered with the preparation of each individual PRA assessment made in support of the individual STI interval requests. The purpose of the remaining portion of this attachment is to address the requirements identified in item 4 above.

This evaluation summarizes the assessment of the Turkey Point PRA capability as measured against the current ASME/ANS PRA Standard (ASME/ANS RA-Sa-2009) [Reference 2], endorsed by NRC Regulatory Guide (RG) 1.200, Revision 2 [Reference 3]. While the NEI guidance document refers to RG 1.200, Revision 1, which includes

only the internal events PRA standard (ASME RA-Sb-2005), this evaluation addresses the broader scope of RG 1.200, Revision 2. This assessment addresses the technical adequacy of the Turkey Point PRA for use in risk-informed applications.

The assessment is based on a series of formal peer reviews and other technical reviews, documented in the peer review reports. This assessment uses the latest Turkey Point PRA model update [Reference 4] and internal flood analysis [Reference 5].

## 2.0 BACKGROUND

### 2.1 RG1.200 and PRA Standard

The ASME/ANS PRA Standard (ASME/ANS RA-Sa-2009) has eight "parts" with technical elements, high level requirements (HLRs), and detailed supporting requirements (SRs). These parts represent the major classes of hazards included in a PRA:

- Part 2, internal events (addressed in Section 3.1),
- Part 3, internal flood (addressed in Section 3.1),
- Part 4, internal fire (addressed in Section 3.2),
- Part 5, seismic events (addressed in Section 3.2),
- Parts 6 to 9, other external hazard events (addressed in Section 3.2).

Note - Part 1 of the PRA Standard is introductory information and does not contain any requirements except configuration control (addressed in Section 3.3).

NRC Reg Guide 1.200, Revision 2 endorses this Standard with minor "clarifications."

The Standard supporting requirements allow the assessment of the portions of the PRA as Capability Category CC-I, CC-II, or CC-III, with increasing scope and level of detail, plant-specificity, and realism. Thus, the overall assessment of PRA capability is the collection of the assessments of the hundreds of supporting requirements.

### 2.2 Turkey Point PRA History

The Turkey Point PRA was originally developed in 1991 for the IPE submittal [Reference 6] as a Level 2 risk assessment of at-power operation of Turkey Point addressing internal events including fires and floods. This PRA was subject to a number of reviews, internal and external, during its preparation as well as extensive review by NRC through national labs following its publication. The first of these reviews consisted of normal engineering quality assurance practices carried out by the organization performing the analysis. A qualified individual with knowledge of PRA methods and plant systems performed an independent review of the results for each task. This represented a detailed check of the input to the PRA model and provided a high degree of quality assurance.

The second level of review was performed by plant personnel not directly involved with the development of the PRA model. This review was performed by individuals from Operations, Technical Staff, Training, and the Independent Safety Engineering Group,

who reviewed the system description notebooks and accident sequence description. This provided diverse expertise with plant design and operations knowledge to review the system descriptions for accuracy.

The third level of review was performed by PRA experts from ERIN Engineering. This review provided broad insights on techniques and results based on experience from other plant PRAs. The review team reviewed the PRA development procedures, as well as the output products.

Comments obtained from all the review sources were incorporated, as appropriate, into the work packages and the final product. Following the Turkey Point IPE submittal to the NRC on June 25, 1991, it was reviewed extensively by the NRC and NRC contractors. In fact, the Turkey Point IPE was one of the few IPE submittals to receive a Step 1 and a Step 2 review by the NRC. The Step 2 review consisted of a team of NRC representatives and contractors visiting FPL to conduct a week-long, extensive review of the Turkey Point IPE. Following these reviews, the Turkey Point IPE was revised in early 1992, and FPL received the NRC Safety Evaluation Report (SER) for the Turkey Point IPE on October 15, 1992. The SER concluded that the Turkey Point IPE had met the intent of GL 88-20.

The Turkey Point Internal Events Peer Review was performed in January 2002 using the NEI 00-02 process. Following the issuance of the ASME PRA Standard and Regulatory Guide 1.200 (RG 1.200), an internal gap analysis was performed where the findings from the original 2002 peer review were incorporated into the overall assessment of the PRA's quality with respect to the Standard's supporting requirements. The current Turkey Point gap analysis uses the RA-Sa-2009 version of the standard as endorsed by RG 1.200, Revision 2.

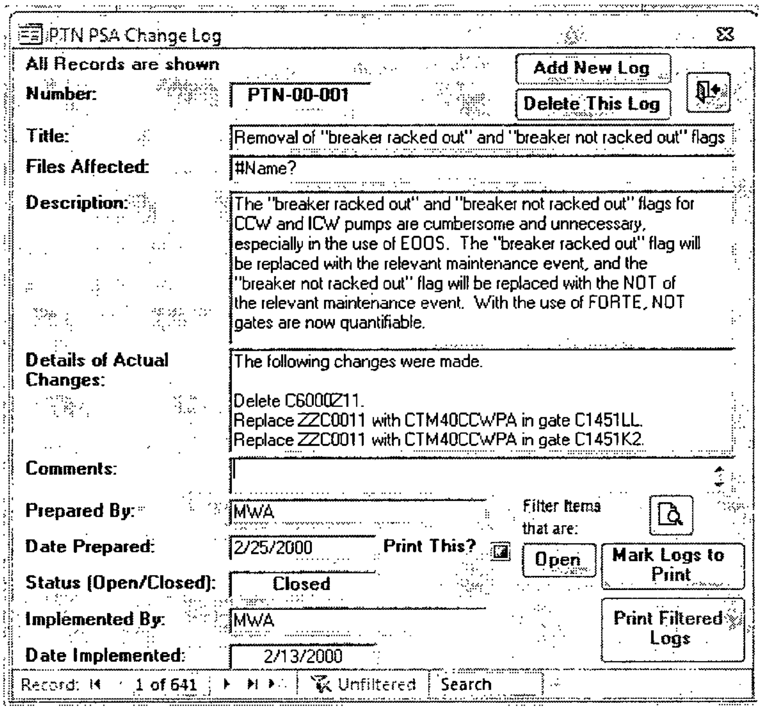
To supplement the original peer review and internal gap analysis, and to further verify the quality of the updated internal events model used in the Fire PRA, in April 2011, a focused peer review was performed assessing the human reliability analysis (HRA) and internal flooding analysis portions of the PRA using the latest PRA standard, ASME/ANS RA-Sa–2009, and Regulatory Guide 1.200, Rev. 2. The internal flooding analysis focused peer review was performed because the latest internal flooding analysis was a much more comprehensive analysis than the original screening analysis that was performed for the IPE [Reference 6]. Although the basic methods used for the HRA had not changed substantially, the HRA focused peer review was performed because of the enhanced HRA dependency analysis and the use of the HRA Calculator software in the latest model, and the fact that HRA plays a significant role in the determination of the dominant sequences and overall risk profile.

Finally, a peer review was performed in October 2013, to assess portions of the PRA model which had received upgrades: 1) Common-cause failure analysis – use of alpha factors; 2) Level 2 analysis – upgrade to the latest methodology; and 3) Interfacing system LOCAs – upgrade to the latest methodology.

Significant findings from the peer reviews, along with their resolutions, are listed in the Enclosure.

## 2.3 Model Change Database

The living PRA is maintained through use of the plant Change Database. A sample screen shot of the input form is shown below.


PTN PSA Change Log

All Records are shown

Number: PTN-00-001

Add New Log

Delete This Log

Title: Removal of "breaker racked out" and "breaker not racked out" flags

Files Affected: #Name?

Description: The "breaker racked out" and "breaker not racked out" flags for CCW and ICW pumps are cumbersome and unnecessary, especially in the use of EOOS. The "breaker racked out" flag will be replaced with the relevant maintenance event, and the "breaker not racked out" flag will be replaced with the NOT of the relevant maintenance event. With the use of FORTE, NOT gates are now quantifiable.

Details of Actual Changes: The following changes were made.

Delete C6000Z11.
Replace ZZC0011 with CTM40CCWPA in gate C1451LL.
Replace ZZC0011 with CTM40CCWPA in gate C1451K2.

Comments:

Prepared By: MWA

Filter Items that are:

Date Prepared: 2/25/2000

Print This?

Open

Mark Logs to Print

Status (Open/Closed): Closed

Implemented By: MWA

Print Filtered Logs

Date Implemented: 2/13/2000

Record: 1 of 641 Unfiltered Search

This database is used to store the details of all modifications, proposed and actual, open or closed, for the Turkey Point PRA model. This includes findings and observations from peer reviews, self-assessments, and issues identified during use and update of the PRA model. The open items are all model enhancements or documentation issues, and have been judged not to significantly impact PRA model applications. Open items will be addressed in future PRA updates, based on the significance of the open item and the scope of the update.

As part of the PRA evaluation for each STI change request, a review of open model changes for Turkey Point will be performed and an assessment of the impact on the results of the application will be made prior to presenting the results of the risk analysis to the IDP. If a nontrivial impact is expected, then this may include the performance of additional sensitivity studies or PRA model changes to confirm the impact on the risk analysis.

## 2.4 Turkey Point PRA Capability Target

The target capability level for the Turkey Point PRA is Capability Category II (CC-II). That is, the goal is to meet all supporting requirements (SRs) at least at the CC-II level. This is the maximum capability level needed by any foreseeable application.

Note that in many supporting requirements, the requirement spans all three capability categories. Thus, if the SR is met, it meets CC III. While CC II is the target, CC III is met in many SRs.

2.5 Assessment Process

The assessment of PRA capability judges the Turkey Point PRA against each supporting requirement in the PRA Standard as "Meets" CC-I, CC-II, or CC-III. If the PRA does not meet the requirements of category CC-II for a specific SR, it is assessed as "Not Met." This assessment is captured in a Microsoft Access database. There is a table in this database with the SR-by-SR assessments from industry peer reviews and internal self-assessments. There is a separate database with tables with Facts and Observations (F&Os) from the WOG peer review and the focused peer reviews, along with their status and resolutions.

## 3.0 EVALUATION

The following sections describe the capability of the Turkey Point PRA for the major Standard parts.

3.1 Parts 2 and 3 - Internal Events and Internal Flooding

The internal events portion of the Turkey Point PRA has been updated a number of times since the original IPE submittal.

As described in Section 2.2, there has been one global peer review, and focused peer reviews in the following areas: HRA, internal flooding, CCF, Level 2, and ISLOCA. Three peer reviews have been conducted against internal event supporting requirements:

- In 2002, a review of all technical elements was performed using the industry PRA Certification process, the precursor to the PRA Standard. The 2002 peer review resulted in 60 findings and observations (2 "A" level, 28 "B" level, 28 "C" level, and 2 "S (Superior) level). All of the findings and observations have been addressed in the model updates following this peer review.
- In 2011, a focused peer review was performed for the elements IF and HR. This assessment replaced the 1999 peer review for those elements that were in scope. This review was done using the current PRA Standard (ASME/ANS RA-Sa-2009). The 2011 focused peer review resulted in 21 findings, 7 suggestions, and 1 strength. All of the findings and suggestions have been resolved, and, where changes were necessary, addressed in a model update.
- In 2013, a focused peer review was performed to review upgrades to the CCF, Level 2, and ISLOCA analyses. This review was done using the current PRA Standard (ASME/ANS RA-Sa-2009) and Regulatory Guide 1.200, Rev. 2. The peer review resulted in 11 findings and 2 suggestions. These findings and suggestions have not yet been resolved in the current PRA model, but will either be addressed via model updates before the implementation of 5b, or shown to have an insignificant impact on the 5b application.

Conclusion

The findings and F&Os that have not yet been resolved will either be resolved in model updates before the implementation of the 5b application, or shown not to represent a significant deficiency in the analyses necessary to support the 5b application.

### 3.2 Parts 4 to 9 – External Events

The NEI 04-10 methodology allows for STI change evaluations to be performed in the absence of quantifiable PRA models for all external hazards. For those cases where the STI cannot be modeled in the plant PRA (or where a particular PRA model does not exist for a given hazard group), a qualitative or bounding analysis is performed to provide justification for the acceptability of the proposed test interval change.

#### 3.2.1 Part 4 - Internal Fire

A fire PRA was performed for Turkey Point as part of the 1991 IPE submittal. Since it was done for the IPE, it was more of a screening analysis to discover any fire vulnerabilities than an attempt to determine a realistic estimate of core damage risk due to fire. It has not been updated since the original submittal.

Turkey Point is an NFPA-805 plant, and therefore has a fire PRA to support the NFPA-805 effort. The fire PRA uses the latest internal events PRA model as a basis. The Turkey Point NFPA-805 fire PRA uses NUREG/CR-6850 guidance as required by NFPA-805, and thus produces a conservative estimate of core damage risk due to fire.

A peer review of the Turkey Point (PTN) Fire PRA was performed in February 2010 at PTN using the NEI 07-12 Fire PRA peer review process, the combined PRA standard, ASME/ANS RA-Sa–2009, and RG 1.200, Revision 2. The purpose of this review was to provide a method for establishing the technical quality and adequacy of the Fire PRA for the spectrum of potential risk-informed plant licensing applications for which the Fire PRA may be used. The February 2010 PTN Fire PRA Peer Review was a full-scope review of all the Technical Elements of Part 4 of the ASME/ANS standard. This report was issued to PTN in April 2010 [Reference 8]. A subsequent peer review performed in March 2012 was a focused scope peer review addressing the FSS, HRA and PRM Technical Elements. The report was finalized and issued to PTN in May 2012 [Reference 9].

The Fire PRA update addressed the Supporting-Requirement-assessed deficiencies (i.e., Not Met or CCI). Completion of recommendations related to Supporting Requirement assessments and 'Finding' F&Os results in a Capability Category II assessment for the majority of the Supporting Requirements.

Conclusion

Based on the completion of peer review recommendations and the assessment of deferred items, the Turkey Fire PRA is adequate to support this application, with the caveat that the PRA is a conservative representation of the fire risk from operation of Turkey Point Station. The Fire PRA model will be exercised to obtain quantitative fire risk insights, but refinements may need to be made on a case-by-case basis.

#### 3.2.2 Part 5 - Seismic Events

Turkey Point is sited in an area of very low seismicity. There is no seismic PRA for Turkey Point. For the seismic portion of the Turkey Point IPEEE (Reference 7), FPL used the FPL site-specific seismic program associated with Unresolved Safety Issue

(USI) A-46 (Generic Letter 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors"). This primarily consisted of extensive walkdowns of the Turkey Point site looking for seismic vulnerabilities.

Staff at Turkey Point recently performed additional seismic walkdowns in response to Near-Term Task Force Recommendation 2.3; the NRC issued a 10CFR50.54 letter on March 12, 2012 requesting that all licensees perform seismic walkdowns to identify and address plant degraded, non-conforming, or unanalyzed conditions, with respect to the current seismic licensing basis. As per the EPRI guidance, two Seismic Walkdown Equipment Lists (SWELs) were generated. The first consisted of a variety of components that support the safety functions of reactivity control, reactor coolant pressure and inventory control, decay heat removal, and containment function. The second consisted of a variety of Seismic Category I components whose failure could lead to a rapid drain-down of the spent fuel pool. Walkdowns were performed in order to verify proper anchorage of the applicable SWEL components and to identify any adverse seismic conditions. No operability concerns were identified. Only minor issues were found that required documentation updates, improved housekeeping, or small repairs due to corrosion or minor concrete cracking. These issues were, or are scheduled to be, addressed through the site's Corrective Action Program.

In 2010, NRC, through Generic Issue 199, calculated pseudo-risk values for all central and eastern US (CEUS) sites, based on IPEEE results with revised seismic hazard estimates by the USGS (USGS-2008) [Reference 10]. This analysis produced a seismic pseudo-CDF estimate of 1.0E-05 per year for Turkey Point. This estimate is believed to represent (at best) an upper bound estimate of the risk, since the results only indicate a bounding plant-level fragility.

In the 2010 Turkey Point LAR for the Extended Power Uprate (Reference 11), an estimate of the seismic risk was made using seismic initiating event frequencies from NUREG-1488 combined with a conditional core damage probability (CCDP) for an unrecoverable grid LOOP from the Turkey Point internal events PRA model. The seismic CDF was estimated to be 1E-08 per year, and the seismic LERF was estimated to be 1E-10 per year.

Conclusion

The fact that Turkey Point is in a region of very low seismicity; multiple seismic walkdowns have been performed to verify the seismic design of equipment important to safety; a bounding analysis of seismic risk by NRC resulted in a 1E-05/ year CDF; and the EPU LAR estimate for seismic CDF of 1E-08 per year supports the conclusion that seismic risk at Turkey Point is minimal and will not be a significant factor in the 5b application.

### 3.2.3 Parts 6 to 9 - Other External Hazards

The risk analyses of the other external hazards were performed and published in the Turkey Point IPE and the Turkey Point IPEEE in the early 1990s and have not been updated since. These analyses were typically bounding and screening in nature, and therefore not well-suited for configuration-specific risk applications. Therefore, in performing the assessments for the other hazard groups, a qualitative or a bounding approach will be utilized in most cases.

3.2.4 Conclusion – External Events

As stated earlier, the NEI 04-10 methodology allows for STI change evaluations to be performed in the absence of quantifiable PRA models for all external hazards. Therefore, in performing the assessments for the other hazard groups, a qualitative or a bounding approach will be utilized in most cases. The Fire PRA model will be exercised to obtain quantitative fire risk insights but refinements may need to be made on a case-by-case basis. This approach is consistent with the accepted NEI 04-10 methodology.

3.3 PRA Model Maintenance and Control

PRA model maintenance and control requirements are described in the PRA Standard, Section 1-5. These requirements are addressed in the current set of Nextera/FPL fleet procedures that address model maintenance and control:

EN-AA-105, Probabilistic Risk Assessment Program

EN-AA-105-1000, PRA Configuration Control and Model Maintenance

EN-AA-105-10000, Control of PRA Documentation and Evaluations

## 4.0 CONCLUSION

The Turkey Point PRA model of record fully meets all the requirements of Part 2 (Internal Events) and Part 3 (Internal Flood) of the current ASME/ANS PRA Standard. All significant findings from peer reviews or other technical reviews have been addressed and closed.

Based on the completion of peer review recommendations and the assessment of deferred items, the Turkey Fire PRA is adequate to support this application, with the caveat that the PRA is a conservative representation of the fire risk from operation of Turkey Point Station. The Fire PRA model will be exercised to obtain quantitative fire risk insights, but refinements may need to be made on a case-by-case basis.

Seismic risk at Turkey Point is minimal and will not be a significant factor in the 5b application.

As stated earlier, the NEI 04-10 methodology allows for STI change evaluations to be performed in the absence of quantifiable PRA models for all external hazards. Therefore, in performing the assessments for the other hazard groups, a qualitative or a bounding approach will be utilized in most cases. This approach is consistent with the accepted NEI 04-10 methodology.

## 5.0 REFERENCES


1. NEI 04-10, Risk-Informed Technical Specifications Initiative 5b Risk-Informed Method for Control of Surveillance Frequencies, April 2007.
2. ASME/ ANS RA-Sa-2009, "Addenda to ASME/ ANS RA-S-2008 Standard for Level 1/ Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications", American Society of Mechanical Engineers and American Nuclear Society, 2009.
3. U.S. Nuclear Regulatory Commission, An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities, Regulatory Guide 1.200, Revision 2, 2008.
4. PTN-BFJR-00-001, PTN PRA Model Update, Revision 10, 7/16/12.
5. PTN-BFJR-11-009, Turkey Point Internal Flooding Analysis, Revision 0, 8/21/13.
6. Turkey Point Plant Units 3 and 4 Probabilistic Risk Assessment Individual Plant Examination Submittal, 6/25/91.
7. Individual Plant Examination of External Events for Turkey Point Units 3 and 4, June 1994.
8. Turkey Point Nuclear Plant Units 3 and 4 Fire PRA Peer Review Report Using ASME PRA Standard Requirements, April 2010.
9. Follow-on Fire PRA Peer Review Against the Fire PRA Standard Supporting Requirements from Section 4 of the ASME/ANS Standard for the Turkey Point Nuclear Plant Units 3 and 4 Fire Probabilistic Risk Assessment, Westinghouse, May 2012.
10. Enclosure "Safety / Risk Assessment" to NRC Internal Memorandum, P.Hiland (Chairman of Safety/Risk Assessment Panel for GI199) to B.Sheron (Director RES), Subject: Safety / Risk Assessment Results for Generic Issue 199, "Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants," September 2, 2010.
11. Turkey Point Units 3 and 4 License Amendment Request for Extended Power Uprate, August 2010.

## *Enclosure - Peer Review Findings*

This table summarizes facts and observations with significance ranking "A" or "B" from the 2002 global peer review and the findings from the 2010 and 2013 focused peer reviews.

| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
|---|---|---|---|---|
| AS-1 | WOG 2002 | The following items were observed related to the success criteria:<br>(1) For small - small LOCAs where high pressure recirculation fails, the ECA-1.1 (Loss of ECC recirculation) actions to refill the RWST via the CVCS and continue injection are modeled. If this succeeds, the modeled endstate is successful core cooling.<br>Although crediting the action is valid, the sequence as modeled has not necessarily reached a stable end state; additional action in the long term is required to put the plant in a stable state. For example, the RWST refill can be argued to extend the accident sequence mission time past 24 hours and therefore beyond the current Level 1 PRA model scope. If the additional time were long, then in taking credit for these strategies the impact on pump and other component run failures, and any additional actions to achieve a stable state should be modeled. In addition, some evaluation should be included regarding potential effects on containment instrumentation or components of increasing water level.<br>(2) For ATWS sequences where "Reactivity Control Late" is asked, the model credits | (1) Perform a more explicit evaluation of the RWST refill function to document the ability to achieve a stable state end state.<br>(2) Consider revising the charging pump modeling to be consistent with plant procedures. | (1) For the small-small LOCA sequences where RWST is credited, secondary cooling is available. Therefore, it is a virtual certainty that depressurization will take place and the leak rate reduced such that RWST refill is viable. In most of these sequences, some fault(s) in the RHR system is preventing successful recirculation or shutdown cooling. While RWST refill may not be considered by some as a stable state, the small flow rate associated with a depressurized small-small LOCA and successful RWST refill makes it fairly stable regardless. The concern over extending the mission time beyond 24 hours is offset by the increasing probability of recovering hardware failures in the cutset which prevented initiating recirculation or shutdown cooling. Further, if RWST refill fails, HHSI from the opposite-unit pumps and RWST is available.<br><br>(2) The charging pump success criterion has been changed to 1/3 charging pumps for emergency boration. |

| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
|---|---|---|---|---|
| | | emergency boration, per procedure FR-S.1. The procedure, and plant training documents, indicate that 1 of 3 charging pumps are needed to ensure at least 60 gpm of borated injection for shutdown. However, the fault tree model (at gate U3WRCL1) implements this as failure if any single charging pump fails. This is incorrect and should be fixed. | | |
| AS-2 | WOG 2002 | Several inconsistencies between the success criteria as stated in the Accident Sequence Analysis Notebook and the linked fault tree model. Specific examples are:<br>a. The Small-small LOCA success criteria for early core heat removal is listed in Table 3 as 2/4HHSI pumps and 1/3 AFW pumps. However, fault tree gate G1PMP3 shows 1 HHSI pump required for small-small LOCA.<br>b. The Small LOCA success criteria for early core heat removal is shown as 2/4 HHSI pumps OR 1/2 RHR and depressurization. However, section 4.1 of the Accident Sequence Analysis Notebook and fault tree gate U3S2CD2 only credit HHSI.<br>c. The Medium LOCA success criteria for early core heat removal is listed as 2/4HHSI pumps in Section 5.1 and Table 5 of the Accident Sequence Analysis Notebook. | Revise the Accident Sequence Analysis Notebook and/or the linked fault tree model to ensure consistency between the documentation and the success criteria modeled in the linked fault tree. | The updated Accident Sequence Analysis Notebook, the new Success Criteria Calculation (PTN-BFJR-08-014), and the updated Revision 9 PTN PRA model (PTN-BFJR-00-001, Rev. 9) resolved the inconsistencies. |

## *Enclosure - Peer Review Findings*

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|---|---|---|---|---|
| | | However, fault tree gate G1PMP3 and the supporting MAAP analyses from the IPE show only 1 of 4 HHSI pumps to be required.<br>d. The success criteria for early core heat removal using the AFW system is described differently in the PTN System Analysis Notebook and the Accident Sequence Analysis Notebook. The fault tree modeling appears to be generally consistent with the criteria stated in the System Analysis Notebook. For example, the System Analysis Notebook states that for ATWS, the AFW system must supply flow from 2 AFW pumps through all six AFW control valves. In Table 8 of the Accident Sequence Analysis Notebook, the ATWS success criteria for AFW is stated as 2 AFW pumps to 3/3 SGs. The structure of fault tree gate A0201 agrees with the System Notebook criteria rather than the Accident Sequence Analysis Notebook. Similar differences were noted in the success criteria descriptions related to the heat removal requirements for the Transient and Small-small LOCA sequences where the Accident Sequence Analysis only gives the pump success citeria without including the requirement to provide flow | | |

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| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
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| | | through at least 3 of 6 flow control valves.. | | |
| AS-3 | WOG 2002 | The Accident Sequence Analysis Notebook lists several systems available to provide various success criteria which are not credited in the linked fault tree. For example:<br>a. The Transient success criteria for long term core cooling does not credit RHR Shutdown Cooling, Low-head Recirculation, RWST replenishment with continued HHSI, Depressurization with Low-head injection and low-head recirculation, continued charging with RWST replenishment, or continued HHSI with opposite Unit RWST.<br>b. The Small-small LOCA success criteria do not credit Bleed and Feed and the long-term cooling success criteria does not credit low-head recirculation or continued HHSI using the opposite unit RWST<br>c. The Small LOCA success criteria for early core heat removal does not credit depressurization and Low-head injection. In addition, the long-term cooling function takes no credit for RHR cooling, low-head recirculation or opposite unit RWST. | Consider removing non-credited systems from the discussion of systems available to meet critical safety functions in the Accident Sequence Analysis Notebook or model the appropriate alternate systems in the linked fault tree. | Continued HHSI using the opposite unit RWST is now credited for long-term cooling of transients. RWST replenishment is not credited, based on the judgment that the leak (2 PORVs worth) is rather substantial, and no secondary cooling is available. The remaining options may be viable, but have many of the same hardware dependencies as HHSR, and consequently will make little difference and will not be added.<br><br>As for small-small LOCA, continued HHSI using the opposite unit RWST has been added. The addition of low-head recirculation with depressurization would have little effect due to shared dependencies with HHSR and, therefore, will not be added. Credit for bleed-and-feed cooling for the S1B sequences has been added to the model.<br><br>For small LOCA, continued HHSI using the opposite unit RWST has been added. As for the addition of the other options, the addition of low-head recirculation with depressurization would have little effect due to shared dependencies with HHSR, and credit for depressurization and low-head injection was not modeled due to the reduced time available because of the larger break size (2-6").<br><br>The suggestion of removing mention of other, non- |

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|---|---|---|---|---|
| | | | | modeled alternative from the AS notebook will not be taken. Removing them would only be removing information that may be useful in the future. |
| AS-4 | WOG 2002 | Event sequence transfers for the following may be conservative:<br>a. The Small LOCA event tree includes a transfer to ATWS on failure of reactor trip. However, analysis at similar plants have shown that core voiding and boron injection from HHSI will shut down the reactor without rod insertion for similar plants.<br>b. The SGTR event tree was revised during the review visit. The new SGTR event tree logic was reviewed. The revised logic appears to be appropriate and generally consistent with plant EOPs. Given that the SGTR is essentially a small LOCA outside containment, Turkey Point does model RWST Refill. Core damage sequence, U3RCD2, may be somewhat conservative. Given secondary heat removal (B) and steam generator isolation (SGI) there will be a gradual RCS cool down and depressurization with, as a minimum, steam relief via the main steam safety valves. The initial SGTR leak rate is typically in the 400 gpm but this decreases rapidly to about 100 gpm as the RCS depressurizes to the HHSI | Plant-specific, realistic thermal hydraulic analyses may result in elimination of currently modeled core damage sequences. If it is decided to retain conservative success criteria, the reason for this decision should be documented in the Accident Sequence Analysis Notebook. | a) No change necessary. Presently, it is an extremely small contributor to risk.<br><br>b) No change necessary. Presently, it is an extremely small contributor to risk. |

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|---|---|---|---|---|
| | | setpoint as a result of the SGTR. Assuming the leak rates remains at about 100 gpm, RWST refill within the 24 hour mission time would not be required as long as the remaining RWST inventory when the leak rate reaches 100 gpm exceeds about 200,000 gallons. (33 hours at 100 gpm). | | |
| AS-5 | WOG 2002 | Several items were noted regarding the ATWS model:<br>(1) The Turkey Point PRA model assumes that ATWS is always the result of mechanical failures (control rod insertion failure, trip breaker failure to open), such that a reactor trip signal will occur. The model therefore ignores the possibility of failure of automatic actuation of AFW and turbine trip; AMSAC is not modeled as being needed for these functions.<br>The Accident Sequence notebook states that "mechanical failure is the principal cause of the control rods failing to insert," and implies that failure of the reactor trip signal is not modeled. However, there is a random failure "LOGIC CIRCUIT FAILS TO GENERATE SIGNAL" (a different gate for each train) that is input to each "TRIP BREAKER RT FAILS TO OPEN" gate. It is not clear what portion of the reactor protection | Consider adding explicit modeling of the RPS equivalent to that provided for the ESFAS logic and consider adding system modeling for AFW to account for variations in the success criteria for secondary heat removal. | 1) The RPS model in the PTN PRA is deliberately simplified. With the myriad of redundant systems which can trip the reactor, coupled with the further redundancy of the operating crew to manually trip the plant based on indicated parameters, it was deemed not worthwhile to produce a detailed model of the RPS. An AMSAC model was added to the PRA.<br><br>2) No changes made. The potentially conservative modeling of the recirculation failures in AFW for ATWS is not a major contributor to CDF, so it was left as is.<br><br>3) A new ATWS event tree was created using the guidance in WCAP-15831-P-A, WOG Risk-Informed ATWS Assessment and Licensing Implementation Process, Revision 2, August 2007. ATWS top event fault tree logic was developed using the new ATWS event tree. |

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| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
|---|---|---|---|---|
| | | system is intended to be represented by these logic circuit gates. Further, common cause failure is not explicitly addressed for these gates, although there is a common cause failure "TRIP BREAKERS FAIL TO OPEN DUE TO COMMON CAUSE"; it isn't clear from the available documentation whether or not logic circuit common cause is included in this event. Further, it isn't clear that the possibility that signal failures leading to failure of both reactor trip and AFW startup or turbine trip, such that AMSAC actuation would be needed, have been addressed in this manner. Development of a more detailed description of the ATWS fault tree logic should be considered.<br>(2) The AFW logic for ATWS sequences, where 2 pumps are required to provide flow to 3 steam generators, includes pump failures due to recirculation (i.e., "mini-flow") failures (e.g., Gate A0010). While this may normally be a valid failure mechanism for these pumps, it would seem that, with the high flowrates required for ATWS response, it would not apply under these conditions. Consider reviewing the basis for this modeling and correcting if necessary.<br>(3) The Turkey Point ATWS model is | | |

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|---|---|---|---|---|
| | | significantly different than the WOG ATWS model presented in WCAP-11993 (and currently being updated for the WOG). Consideration should be given to adopting the revised WOG model after it is completed and reviewed by NRC. | | |
| AS-7 | WOG 2002 | The SGTR event tree branches to the ATWS tree on failure of reactivity control. The ATWS tree does not address the secondary side isolation and depressurization needed to mitigate an SGTR. | Consider discussing this in the ATWS or SGTR writeups to provide justification for not including this logic (i.e. negligible impact.) | The SGTR frequency is 3.2E-03 per year. Couple that with the pre-eminent ATWS "failure-to-scram" cutset of NRDPHYSICAL, the physical failure of the rods to fall in the core" with a probability of 1.2E-06, and before you have considered the probability of other failures necessary for core damage, you are already at a frequency of 4E-09 per year. SGTR does appear in the ATWS top logic as an initiator but it is true that the ATWS top logic does not take into account the special requirements to mitigate a SGTR. However, to include such logic would have no appreciable effect on the quantitative results of the model, baseline or configuration-specific. |
| AS-8 | WOG 2002 | The potential for an induced SGTR is not addressed in the ATWS model. Nor is it addressed for the transient model associated with main steam line break. | The accident sequence notebook should be updated to include a qualitative discussion of the basis for excluding induced tube ruptures. | The ATWS event tree was upgraded in the PTN Accident Sequence Analysis for RG 1.200 using guidance in WCAP-15831-P. In this WCAP, it states that current studies have indicated that the SG tubes will withstand an ATWS pressure peak that results in RCS failure. |
| AS-9 | WOG | The SGTR event tree does not have complete sequence delineation. For the | Ensure that there is sufficient basis for the | The SGTR event tree was revised such that no credit for RCS cooldown and depressurization is given for |

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| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
|---|---|---|---|---|
| | 2002 | case with failure of isolation and failure of HHSI, cooldown and depressurization to RHR conditions is asked and, if successful, no further delineation is provided in the model. There should be some T/H analysis to show that the plant can be cooled down to RHR entry conditions without HHSI given a SGTR. | modeled accident sequences. | sequences where SG isolation and HHSI fail. |
| DA-1 | WOG 2002 | NUREG/CR-4550 was followed to develop CCF. NUREG/CR-4550 was issued in 1986. The approach addressed in NUREG/CR-4550 may have been out of date. NUREG/CR-4780 (or equivalent) systematic approach should be followed. | Consider revising CCF modeling based on the NUREG/CR-4550 systematic approach. A more updated systematic approach (such as NUREG/CR-4780 or equivalent) should be followed. | The Turkey Point CCF model was updated to reflect the alpha-factor approach and data from INEL 94/0064. |
| DA-2 | WOG 2002 | The test and maintenance probabilities used for individual components are based on actual outage time as collected by the plant. The component outage time was clearly collected over the period of time the plant was in Modes 1, 2, and 3.<br>The fault trees and event trees use several cross-ties from AC power, HHSI, and AFW. In the use of these cross-ties, the opposite unit components have T&M events. The | Consider revising the T&M event probabilities for the opposite unit components to account for unavailability over the total period of demand. As stated above, this can be done at the fault logic level or in the data probabilities. | Logic was introduced to the model to change the opposite-unit EDG test and maintenance probability during outage conditions through the use of flags representing the operating mode of the unit. These flags were also used to model the effect of the opposite unit's mode on the different system crossties. |

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|---|---|---|---|---|
| | | opposite unit may be in Modes 4, 5, and 6 at the time of demand and the desired equipment may have lesser Tech Specs than those assumed for power operation. The T&M event probabilities for the opposite unit components must consider unavailability over the total period of demand, not just during power operation. This can be done at the fault logic level (with house events for OOS) or in the data probabilities. Currently, neither is done. The most important case of this is the DG's. The DG T&M unavailability is about 6E-3 (55 hours per year). If the OOS time for major overhaul were considered, the unavailability would be .03 to .05. | | |
| DA-3 | WOG 2002 | There is no clear guidance for component boundaries and grouping. The Bayesian approach addressed in the Data Process Procedure is inconsistant with the approach applied in Rev 4. In the data process procedure, the lognormal distribution will be convered to alpha and gamma first, then perform Bayesian updating. In Rev. 4, IP6, 7, 8, 9 updating in Rev. 4 are not following the method addressed in the procedure. | Consider updating the data process procedure to be consistent with the approach applied in Rev. 4. | Component boundary definitions and consistent Bayesian updating are part of the latest data update (PTN-BFJR-02-026, Rev. 1). |
| DA-4 | WOG | The latest data updating was done in 1995 | Review industrial events | The data used in the latest model update has plant- |

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|---|---|---|---|---|
| | 2002 | based on plant specific data from 1990 to 1994, and the generic database developed in 1989. | after 1989 to update the generic database and update the reliability data based on current plant specific data. | specific data derived from plant records from 1992 through 2006, and generic data from the latest sources, primarily NUREG/CR-6928. |
| DA-5 | WOG 2002 | Loss of 4kV buses A and B are modeled as special initiating events. The normal power supply to these buses is Startup Transformer 3 with emergency power from the diesel generators. Since loss of power to 4kV Bus 3A or 3B will result in a plant trip, it is unclear that maintenance would be performed on the startup transformers during at-power conditions unless there are unmodeled crosstie arrangements during the maintenance. It was noted that the maintenance events for the 4kV buses (ETM3A4KV and ETM3B4KV) are set false prior to quantification. It would seem that the same should be true for event ETM33SU. This might be negligible, except the the maintenance unavailabilities are almost two orders of magnitude greater than the random failure of the transformer. | Remove maintenance events for components which cannot be removed from service during at-power operation. If these events are required for maintenance rule performance criteria sensitivity analysis, then it should be confirmed that all such events are set false false in the baseline quantification flag file. | The normal power supply to 4KV buses A and B is not the startup transformer, but the auxiliary transformer. The startup transformer supplies power to the 4KV buses only if power from the aux transformer is not available, such as following a reactor trip. Therefore, the startup transformer can be removed from service during power operation, and occasionally is. |
| DA-8 | WOG 2002 | The diesel FOT pump is not explicitly included in the PRA. It is stated that the FOT is assumed within the failure events for tank | Verify the component boundaries of the day tank and DG so that it is clear | The pumps do not have to be added to the model for the U3 EDGs as the U3 day tanks gravity-feed the EDGs, and have enough capacity (4,000 gallons each) |

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|---|---|---|---|---|
| | | failure. While this may be true, the CCF of the FOT pumps is therefore not included, because there is no CCF for the daytanks. | where the FOT pump is subsumed. Verify that CCF of FOT is similarly subsumed in the higher component. | to supply their respective EDGs for the entire mission time. The situation for U4 is different as each day tank only contains 650 gallons. Therefore, the fuel oil transfer pumps were added to the model for the U4 EDGs. |
| DE-2 | WOG 2002 | The Flooding analysis considered component vulnerability to both flooding and spray effects. Multiple screening criteria were employed to eliminate areas from further consideration. The three remaining areas were then analyzed in more detail to determine a CDF from flooding.<br>A CDF of approximately 5E-7 was calculated for flooding and determined to be not significant relative to then overall risk (IPE CDF of 3.7E-4). The current model maintains cutsets of lower CDF than these flooding cutsets. The conclusion that the flooding is not significant is no longer supported. | Review flooding analysis to determine if the screening and flooding initiator frequency calculations are still current using updated methodology, models and assumptions. | The internal flooding analysis has been completely revised for RG 1.200. See Calculation PTN-BFJR-11-009, Rev. 0. |
| IE-1 | WOG 2002 | The PTN PRA updates are not documented in a single document. There is not a single IE system notebook that contains all pertinent information and references for the IE task. The basis for the current PRA is some cases go back to the 1991 IPE. Updates have been performed as needed. Each update is | Develop integrated notebooks with all revisions. | As part of the RG 1.200 effort, notebooks were prepared for each part of the PRA update process: AS, IE, SC, HRA, etc. |

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| | | documented as it is done and filed by time of update, not subject matter. It was very difficult to find the current status of an analytical issue. | | |
| IE-2 | WOG 2002 | The disposition of dual unit initiators and dual unit success criteria is not clear. The following observations were made:<br>1) Loss of grid is called a "dual unit initiator" with a frequency of 0.053. The derivation for 0.053 is dominated by switchyard faults, which the IPE notebook implies would be a single unit initiator.<br>2) Loss of a DC bus on either unit will require the other unit to shutdown, but it is not explained why this is not a dual unit initiator.<br>3) There are no guidelines for dual unit success criteria.<br>There are several shared systems at PTN. The success criteria for Unit 3 assume complete availability of the Unit 4 systems to mitigate events at Unit 3. There should be an identification of dual-unit initiators and development of associated dual-unit success criteria. | Clarify the nature of dual unit initiators and dual unit success criteria within the PRA. | 1) The LOOP initiators are now split into 5 different initiators. There are 4 dual-unit initiators: plant-centered, weather-induced, grid-related, and grid blackout; and 1 single-unit intiator. The two units share one switchyard, so it is assumed that switchyard faults cause a dual-unit LOOP. The single-unit LOOP is dominated by unit-specific startup transformer faults which are on the periphery of the switchyard and cause a loss of offsite power to only one unit.<br><br>2) This is because the other unit would have to shut down due to Tech Specs. As such, it would not be an immediate reactor trip, but a controlled shutdown.<br><br>3) Dual-unit success criteria are discussed fully in the AS Notebook and the SC calculation PTN-08-014. The effects of the dual-unit initiating events on the opposite-unit systems are modeled. |
| IE-3 | WOG 2002 | The initiator for Pressurized Thermal Shock is considered "out of scope" with no | Provide justification for elimination of these | Added RV Rupture IE in PTN-04-011. Research over the last few years by NRC, EPRI, DOE, MRP, and others |

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| | | justification. PTS is not out of scope for PRA. Discussion with PTN PRA staff indicate that from a licensing perspective, it has been determined to be a resolved and therefore should not be in the PRA. This should be explained, with a probabilistic explanation of why it is a small contributor.<br>The initiator for Reactor Vessel Rupture is considered out of scope with no justification. | initiators or include in model. | has shown PTS to be a non-issue for plants like Turkey Point. |
| IE-4 | WOG 2002 | PTN has several shared systems. These include HHSI, AFW, and DG. The configuration of these systems may depend on the status of the unit. For the purpose of system sharing, the opposite unit equipment is always assumed to be available in Mode 1 operability.<br>The following observations were made:<br>1) The T&M unavailability for DG implies about 50 hours a year OOS. This can not include time for annual overhaul, (which is done at shutdown). When the opposite unit is in Mode 6, the DG tech spec is reduced to 1 DG. The PRA does not capture this dependency on plant status.<br>2) When Unit 4 is in Mode 5 or 6, the HHSI for unit 4 is cooled by CCW on unit 3. The PRA does not capture this. | Develop and implement criteria for modeling dual unit plant operating status. | See resolution of DA-2 for 1) and 3). 2) is addressed by PRA Change PTN-02-005, which is implemented in the current PRA model. |

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| | | 3) there are no overall guidelines and criteria for treatment of the opposite unit's operability and it's affect on equipment availability. | | |
| IE-5 | WOG 2002 | There are several methods for quantifying IE frequencies. They are derived from a) plant specific experience, b) NUREG/CR-5750, c) plant specific fault trees, d) CE Owner's Group for LOCA's. It was not possible to find, in one place a summary of the quantification methods. | Consider creating a summary table consisting of initiating event category, frequency, and quantification method. | See Initiating Events Notebook, Rev. 3 and PTN data update calculation, PTN-BFJR-02-026, Rev. 1. |
| IE-7 | WOG 2002 | The level of independent technical review of PRA changes is indeterminate. There are no comment and resolution sheets for the PRA modification process. There is only a signoff sheet on the overall update package (which contains several individual changes). | Provide evidence of an independent technical review. Document how review was conducted and what comments were made during the review. | There is now a comment and resolution section in the model update calculations. |
| IE-8 | WOG 2002 | The system notebook states that MSIV Closure and Loss of condenser vacuum are classified as a Reactor trip with full MFW available. There are 2 issues on which this could conflict.<br>1) The availability of condensate water may be affected by loss of condenser, but the staff states that there are 2 CST's with make-up and transfer capacity.<br>2) the operability of steam relief from the | Provide a basis for classifying MSIV Closure and Loss of condenser vacuum as Reactor trip with full MFW available. | The PCS system notebook no longer makes this statement. However, the statement is irrelevant as the determination of the IE frequency for LMFW is solely based on actual plant-specific and industry experience.<br>Steam relief of the SGs is modeled. |

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| | | SG, whioch is not modeled in the PRA. The basis for classifying these IE as reactor trip is not given. But, the affect on the results (if this is misclassified) is not important because the frequency for the IE are derived based on industry and plant specific data and do no account for each individual category. | | |
| IE-9 | WOG 2002 | Random reactor coolant pump seal failure has not been included. From NUREG/CR-5750, this event can be about 1E-3. The S1 frequency is derived from pipe rupture failures only. It does not include component leakage, RCP seal LOCA, or any other sources of small leakage. | Include random RCP seal LOCA as an initiator. | A review of NUREG/CR-5750 revealed that the random seal LOCA frequency is 2.5E-3 per year, and is based on 2 events: a 1975 event at Robinson-2, and a 1980 event at ANO-1. The incident at ANO-1 can be discounted not only due to the fact that it was 20 years ago and design changes have likely been made to preclude similar events, but also due to the fact that ANO-1 is a B&W plant with substantial differences in RCP and RCP seal design. The incident at Robinson-2 was discounted due to changes in seal design and seal-related operating practices and procedures implemented in the last 37 years. |
| MU-1 | WOG 2002 | Performed a quick review of the PRA Change Access database PRAUPDATELOG.mdb with help of Turkey Point PRA staff. Searched the PCN table until a PCN which had a PRA impact was found. This PCN, 94131, involved a change to remove a valve, CV-4-32202 , and replace | Closer adherance to process. | Fixed. Should have been PTN-03-026. |

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| | | it with a spool piece. This PCN pointed to PTN-99-026, which in turn pointed to PTN-BFJR-99-010 for final resolution. PTN-BFJR-99-010 was the update of the level 2 analysis and did not discuss the valve change at all. Additional investigation revealed that PCN 94131 should have pointed to a different PRA change form and calculation. | | |
| MU-2 | WOG 2002 | STD-R-001 has a requirement for signoff by the preparer, an independent reviewer and the RRAG supervisor. The PRA update calculations that were reviewed had all the required signatures. However there were no review notes or discussion of the disposition of review comments in the various calcs examined by the peer reviewers. Further, the peer reviewers found examples of inconsistencies in several signed-off notebooks (e.g., Accident Sequence Notebook included incorrect success criteria for S2 LOCAs), and examples of errors carried through several PRA Update Calc revisions (e.g., CDF cutsets that included single failures in emergency boration pumps for ATWS, which should have required multiple failures). | Consider augmenting existing RRAG processes by defining such measures as a standard, expanded level of detail in description of PRA changes being incorporated, items to be checked for by reviewers, etc. In particular, the purpose/basis for each change should be defined in the change packages. This should provide the reviewer with enough information to determine if the detailed changes actually are sufficient to fully address the basis for the change. | There is now a comments and resolutions section in the model update and other PRA Group calculations.<br><br>Details of each change are documented in the PTN Change Database. Each model update includes a table of the changes implemented for that model update and reasons for those changes.<br><br>Consistency issues between the Accident Sequence Analysis, the Success Criteria calculation, and the model update calculations have been resolved in RG 1.200-related upgrades of all of these documents.<br><br>The other issues are treated separately in other F&Os. |

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| MU-3 | WOG 2002 | Procedures STD-R-001, Rev. 0 (Software Control Procedure) and STD-R-002, Rev. 5 (Update and Maintenance) govern model control.<br>The computer models (e.g., current and previous model files such as *.CAF and *.BE) for the Turkey Point PRA are maintained on a server (g:nis\PSA). The server is backed up daily and therefore provides secure storage. Access to files on this server is limited to those with permission and is on a read-only basis. In addition, computer models are stored on a CD and sent to the document control center. A second copy is maintained locally. Model changes are also maintained on this server.<br>This same process is used for the PRA software (e.g., EOOS, CAFTA, FORTE). | | NA |
| MU-4 | WOG 2002 | STD-R-002 requires a data update every 5 years. However, it does not appear that Turkey Point has updated the reliability data since 1995 even though the common cause failure data, the human factors data, the initiating event data and the unavailability data was updated in 2000. | Update the reliability data. Ensure adherence to procedures | Data updated in current PRA model using the data documented in the data update calculation, Rev. 1 of PTN-BFJR-02-026. |
| MU-5 | WOG 2002 | STD-R-002 includes a set of criteria for when to perform a model update. The key | Revise the procedure, STD-R-002 to incorporate a | Changed procedure to have a maximum interval of five years between model updates. |

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| | | criteria are if the change has a significant impact on CDF or risk insights. However, there are no criteria as to what constitutes a significant impact. Given that there is no fixed update period, there is a concern that the number of "minor" changes pending could build up until the combined impact is significant without triggering an update. | fixed update equivalent to the fixed data update schedule to preclude an unending build up minor changes that could have a significant cumulative impact. The procedure should also be revised to include a process for evaluating the potential cumulative impact of pending changes and triggering a model update if the cumulative impact of the pending changes is judged to be significant | Whether minor changes constitute justification for a model update is determined by the model custodian. |
| MU-6 | WOG 2002 | Turkey Point does not appear to have a single list of "Living PRA Applications" | Establish a controlled list of PRA applications and revise the procedure to require at least a qualitative evaluation of all applications on the list be performed and documented following each model update. | List added to STD-R-002 (see Table 5). |
| QU-1 | WOG 2002 | Loss of RCP seal cooling sequences following transient initiating events are | Those transients which result in a 21 gpm leak rate | Transient initiators are input to all of the transient sequences. |

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| | | transferred to the S1 LOCA event tree with a ZZSL flag event set to 2.1E-1. However, it is not clear that the 79% of loss of seal cooling events resulting in 21 gpm per pump seal leakage are being retained in the transient event sequences. | would be treated as normal transients and would be accounted for in the transient sequences. | |
| QU-10 | WOG 2002 | The truncation limit for the CDF results is consistent with the grade 3 requirements, but the same core damage results are used as the basis of determining the LERF. This effectively results in the LERF truncation level being less than 1E-4 below the total LERF. | Consideration should be given to performing sensitivity studies at lower LERF truncation levels for applications where LERF is important. | In the Rev. 9 PTN PRA model, the Level 2 model is incorporated directly into the fault tree and quantified separately. The truncation for the quantification is more than 1E-4 below the mean LERF value. |
| QU-2 | WOG 2002 | The guidance provided for the quantification process is IPE vintage. Several new codes are being used in the current process which did not exist at the time of the IPE. No guidance procedures currently exist to control key processes involved in model integration and quantification such as:<br>a. Criteria for development of the mutually exclusive events file<br>b. Selection of truncation value<br>c. Quantification on a sequence basis versus quantification of top gate<br>d. Process for breaking circular logic in the | Consider establishing clear guidance for the selection of mutually exclusive event combinations, the use and development of flag files to control the quantified system configuration, the determination of an appropriate truncation level, and acceptable inputs for performance of uncertainty analysis. | Changes to the mutually exclusive event combinations, flag file, and recovery rule file that have occurred since 1998 are documented in the PTN Change Database and the model updates. They document the mutually exclusive event combinations, flag file, and recovery rule file with justification for their content. Truncation level is set as low as the hardware and software will allow, or until convergence is achieved. Uncertainty analysis input is described in the model update calculations. |

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| | | single top linked fault tree (i.e., selection of proper gate level for performing the logical break, naming scheme to be used for gates in the new system fault tree, etc.<br>e. Process for development of flag files for the baseline quantification to ensure the quantified configuration represents normal plant operation practices<br>f. Selection of parameters for input to the UNCERT code for uncertainty calculation | | |
| QU-3 | WOG 2002 | The quantification of a linked fault tree model involves the proper integration of several files which can affect the results. For example:<br>a. The quantification flag file is used to set logic flag events true or false to represent normal system alignment. At PTN, this flag file is also used to set certain maintenance events false.<br>b. The mutually exclusive file is used to remove cutsets from the results file which contain certain combinations of events representing disallowed maintenance or illogical event combinations (i.e., events for failure to open and spurious opening of the same valve in a single cutset).<br>c. The recovery rule file is used to add recovery events to the cutset results ased | Consider developing a documentation package for the flag file, mutually exclusive events file and the recovery rules which provides the basis of each item in the respective files. Cross-disciplinary review of the flag file and mutually exclusive events file by plant personnel may also be considered. | See QU-2. |

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| | | on the appearance of certain combinations of failure events. At PTN, this process is also used to apply human error factors to the quantification results. Since these files control vital processes during quantification, independent review and thorough documentation is needed to ensure that the quantification results do not exclude valid failure sequences. The current mutually exclusive events file (PTN2KMEE.TXT) was changed as a result of the addition of new T&M events for LC/SWGR HVAC AHUs and Sump Level Indicators. The calculation package includes a description of "add double maintenance events for these basic events to mutually exclusive events." However, no justification for making the events mutually exclusive or specifying the combinations that are mutually exclusive is provided. In addition, the review of the mutually exclusive events file indicates that some complimentary combinations related to AFW pump maintenance may not be included. While this would lead to conservative results due to failure to remove invalid cutsets, the addition of inappropriate mutually exclusive combinations would have the opposite result. Similar errors can be introduced | | |

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| | | through the recovery file through the inappropriate application of recovery events to sequences which do not represent the conditions assumed in the HRA analysis. | | |
| QU-4 | WOG 2002 | The current practice is to run the baseline quantification with the flags set to use Loop A as the broken loop for LOCA events. From discussion with PRA group personnel, this was decided based on evaluations during the IPE which did not identify any asymmetry due to broken loop and operating equipment alignment. However, there was no evidence that this evaluation has been performed since the IPE to ensure that plant changes and changes to the linked fault tree have not inadvertently introduced asymmetry. | Consider performing future quantifications with flags set to split fractions rather than True or False. This will ensure all complimentary cutsets appear in the quantification results and provide an opportunity to identify any asymmetry introduced through plant modifications or model updates. | The flags are now set to split fractions. |
| QU-5 | WOG 2002 | Documentation was not available to indicate that PTN has performed qualitative evaluation for causes of uncertainty, such as:<br>a. possible optimistic or conservative success criteria,<br>b. suitability of the reliability data,<br>c. possible modeling uncertainties (asymmetry or other modeling limitations due to the method selected), | To meet the grade 3 criteria for sub-elements QU-27 and QU-28 (uncertainty analysis criteria), perform and document a more systematic uncertainty evaluation to identify potential uncertainties due to such items as modeling | In the PRA model updates, sensitivity analyses are run to show the effect of key modeling assumptions. Parametric uncertainty is addressed in the model updated calculations. Comprehensive uncertainty analysis evaluations are provided in the Uncertainty Analysis Notebook. |

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| | | d. degree of completeness in the selection of initiating events, and<br>e. possible spatial dependencies. | assumptions, success criteria conservatisms, data, etc, Identify the likely impacts of these sources of uncertainty on results, and perform sensitivity analyses as appropriate to achieve an understanding of whether/how they may affect risk-informed decision-making using the PRA. | |
| QU-6 | WOG 2002 | Recovery of offsite power is applied to sequences where offsite power may not recover the lost function. This occurs in two types of circumstances:<br>1) for non-grid-loss initiators, LOSP (and SBO) can occur due to failure in the AC power distribution system. XROSPi is applied. The recovery probability of XROSPi is based on the NSAC document for restoration of offsite power to nuclear plants. The sequence in question is cause by a failure of a breaker or transformer at the plant. It is not clear that the recovery probability is applicable.<br>2) for some SBO sequences where all SG heat removal is lost, XROSPi is applied. | Verify that the recovery of offsite power is a) applicable, b) will recover (with high probability) the lost function, c) has an applicable probability. | In the current model update, the recovery of offsite power is not credited for cutsets where the recovery of offsite power does not recover mitigating equipment sufficient to avoid core damage.<br><br>Recovery of offsite power is not credited for sequences where the LOOP simply acts as a reactor trip initiator (and loss of MFW) versus a support system loss. |

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| | | Although AC power is available, it is not clear that SG Heat Removal is restored. The SG heat removal is provide dby 3 TD pumps and 1 diesel driven pump. If these fail, restoration of AC power does not make them operable.<br>For example, there is a cutset at 1.274E-9 which is loss of 4KV 3A with failure of aux transformer. There is a recovery for XROS19 and EHFPXTIE.<br>The correctness and reasonableness of this practice is questioned. | | |
| QU-7 | WOG 2002 | A review of the dominant cutsets revealed that the failure of the operators to trip the Reactor Coolant Pumps following a loss of oil cooling does not appear to be modeled in the Turkey Point PRA model. This has been found to be a dominant contributor to core damage at similar plants. | Evaluate the applicability of this RCP seal failure mode to Turkey Point and modify the PRA model or documentation as appropriate. | Added CHFPSTPRCP, failure to stop RCPs given loss of CCW, to the model. |
| QU-8 | WOG 2002 | The subtier criteria for a grade 3 on this element considers the following to be indicative of a good understanding of the dominant risk contributors:<br>a. The accident sequence results by sequence, sequence types, and total should be reviewed and compared to similar plants to assure reasonableness and to identify | Consider expanding the discussion of the quantification results in the calculation packages or developing a PRA Summary Document containing this type of evaluation for each revision. | a. A comparison of PTN CDF cutsets to Robinson's CDF cutset was made and is documented in the Quantification Notebook. Where differences in the cutsets occurred, they could be explained by design or data differences.<br>b. A list of the top 50 cutsets is provided in the model updates.<br>c. Initiating event pie charts, system importance |

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| | | any exceptions.<br>b. A detailed description of the Top 10 to 100 accident cutsets (CAFTA or NUPRA) or accident sequences (RISKMAN) should be provided because they are be important in ensuring that the model results are well understood and that modeling assumption impacts are likewise well known.<br>c. The dominant accident sequence groups or functional failure groups should also be discussed. These functional failure groups should be based on a scheme similar to that identified by NEI in NEI 91-04, Appendix B. There is no discussion of results in the calculation packages for updates provided to the review team to indicate that this type of evaluation is done of the quantification results. Also, the calculation packages provide no discussion of how the dominant cutsets or impotant systems were affected by the changes to the model when compared to the previous revision. | | charts, and a table listing the individual sequence contributions are included in each model update calculation. |
| SY-1 | WOG 2002 | Module GMM3GK100 contained failures for 3 valves in the mini-flow recirculation line for HHSI 3A. Only 2 of these valves could be found on Figure 10 on page 44 of 127 in the PTN System Analysis Notebook. | Update the simplified schematics to include all modeled components or provide some other means for identifying the location of all modeled components | Fixed in the HHSI system notebook update for RG 1.200. |

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| SY-2 | WOG 2002 | The RHR/LHSI model for recirculation assumes that failure of either the RWST level indication or the sump level indication will result in a failure to switchover to recirculation. The model for failure of the sump level indication includes common cause miscalibration but common cause miscalibration of the RWST level indicators is not included in the model and no basis could be found for the exclusion of this failure.<br>The CCW model does not include the relief valve, or the surge tank level instrumentation. | The discrepancy between definition of dependencies in section 3.6.5 and the model should be resolved and the model revised accordingly. | Added JHFA3RWSTLVL, "common cause miscalibration of U3 RWST level indicators" to gate J504. Added JHFA4RWSTLVL, "common cause miscalibration of U4 RWST level indicators" to gate U4J504. |
| SY-3 | WOG 2002 | The level of detail for the electrical systems is not consistent with normal industry practice. For example:<br>a. Modeling of the diesel generators includes leakage from the fuel oil storage tanks and piping, but does not include failure of the fuel oil transfer pumps. This was noted as a deficiency in the Revision 1 update, but no clear resolution was noted. It is implied that the transfer pump failures are included in the tank leakage event, but there is no documentation that has been found for the inclusion of the pumps in the tank boundary for data collection and | Explicitly model the diesel fuel oil transfer pumps and grid/switchyard failure. | a) The pumps do not have to be added to the model for the U3 EDGs as the U3 day tanks gravity-feed the EDGs, and have enough capacity (4,000 gallons each) to supply their respective EDGs for the entire mission time. The situation for U4 is different as each day tank only contains 650 gallons. Therefore, the fuel oil transfer pumps were added to the model for the U4 EDGs. See PTN-2-034 for addition of diesel fuel oil transfer systems to the model.<br><br>b) Switchyard failure following non-LOSP initiators is included in the LOSP event database. |

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| | | calculation of the tank leakage event probability.<br>b. Only Startup transformer failures are modeled for offsite power feeds following an initiating event. Switchyard failure following non-LOSP initiating events is not included. | | |
| SY-4 | WOG 2002 | Gate E3093H models failure of the Charging Pump 3C breaker to open on undervoltage. However, the breaker failure event included under this gate is ECBR335008, Breaker 35008 Transfers Open. | Replace event ECBR335008 with the proper basic event coding to ensure the correct event probability is assigned. Review similar logic gates to ensure this is not a generic modeling concern. | This has been fixed. |
| TH-1 | WOG 2002 | The basis for requiring or dismissing HVAC requirements is poorly supported and inconsistent throught the PRA. The following observations were made:<br>1) The HVAC system notebook and DG system notebook require HVAC for EDG rooms, DC equipment room and 4160 equipment rooms. The analysis is based on design basis calculations from A&E done in 1985-1988.<br>2) Recent updates use engineering judgment and plant experience from system | Consider revising analysis to better support HVAC requirements. | The HVAC analysis has been fully revised. GOTHIC room heat-up calculations have been performed for many of the HVAC-cooled areas containing PRA components, especially those where the need for HVAC was questionable. The heatup calculation results were compared to the survivability temperatures of the PRA components in the various rooms and the dependencies applied accordingly, |

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| | | engineer to dismiss need for HVAC to 4160 and DC power rooms.<br>3) The current fault trees require HVAC for DC room and EDG room for LOCA events only.<br>4) GOTHIC or other room heat up calculations have not been done to support room cooling of these rooms.<br><br>Discussions with plant staff during the Certification indicate the following requirements for HVAC:<br>A) Unit 3 DG does not need HVAC.<br>B) Unit 4 DG need HVAC whenever they operate<br>C) the switchgear room needs ventilation to protect the 480v transformer. The switchgear ventilation system is normally running. Remedial action via opening doors and running an exhaust fan is sufficient to maintain temperatures. The lead time and indication of loss of ventilation is sufficient enough that loss of switchgear room ventilation is not considered an initiating event.<br>D) The inverter and battery charger need room cooling. Remedial action is available with plug-in, portable fans, but recovery | | |

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| | | time is on the order of 1 hour. | | |
| TH-3 | WOG 2002 | It is difficult to determine, from the PRA notebooks, which codes or methods of analysis are used for specific success criteria determination, or why these methods are appropriate. For example, applications of the MAAP code, particularly the IPE-vintage 3b version, may require some justification or check for applicability (e.g., avoiding use of MAAP 3.0b for rapid RCS depressurization scenarios, which typically require capabilities beyond what was available in that particular version of the code).<br>Further, it is difficult to determine the specific analytical bases for specific success criteria used in the model. While the Accident Sequence Notebook includes a summary of success criteria for each event, reference for the bases for the success criteria is to the IPE, which does not provide additional information on this subject. | Provide clearer traceability of success criteria to analytical bases, at least for "non-obvious" criteria (e.g., for those whose basis is other than FSAR). Consider developing a clear set of guidelines establishing the acceptable range of applications of various types of codes and calculations. | The updated Accident Sequence Analysis Notebook (Revision 3), the new Success Criteria Calculation (PTN-BFJR-08-014, Rev. 0), and the updated Revision 8 PTN PRA model (PTN-BFJR-00-001, Rev, 8) resolved this F&O. |
| TH-4 | WOG 2002 | The LOCA break size definitions for the PRA are based on different criteria than those for most other PRAs. This is acceptable if the underlying analyses provide sufficient basis for the definitions. | Because the break size definitions are central to the LOCA modeling for the Turkey Point PRA, there should be, in the event | The updated Initiating Events Notebook (Revision 3), the updated Accident Sequence Analysis Notebook (Revision 3), the new Success Criteria Calculation (PTN-BFJR-08-014, Rev. 0), and the updated Revision 8 PTN PRA model (PTN-BFJR-00-001, Rev. 9) provide |

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| | | A series of MAAP 3.0b analyses was performed for the Turkey Point IPE. The available documentation consists of the Accident Sequence Notebook descriptions and success criteria summary and an internal memo from the IPE, which provides a summary listing of the MAAP cases that were run, along with an indication as to whether or not core uncovery/vessel failure occurred. Reviewer note R11 to table TH provides a comparison of the definitions and their bases, with focus on the injection phase, as discerned from this information: From the comparison in note R11, it can be seen that the principal difference in size definitions (aside from the names used) is in the PTN Medium Break category, which is essentially the lower end of the typical Large Break category.<br>Comments on the above are as follows:<br>The available documentation provides the basis for some, but not all, of the size ranges noted above. Information provided in FPL memo NF-90-450 (October 19, 1990) provides sufficient information to serve as a basis for the S1 and S2 ranges and the lower end of the Medium LOCA range. But it does not provide any basis for the upper end of the Medium LOCA / lower end of the Large | tree notebook or appendix, a clear discussion of the bases for the selections, including reference to the spectrum of analyses performed and the specific set of MAAP or other analyses that define the size range for each size break.<br>Consideration should be given to evaluating and documenting the effect on PRA results and risk insights resulting from using these (as opposed to more "traditional") definitions.<br>Confirm that all definitions are based on analyses performed using appropriate codes and modeling assumptions, especially for the larger break size definitions (i.e., those in the range of 3" and above). Consider confirming the results of key earlier MAAP 3.0b | justification for the LOCA break sizes. |

## *Enclosure - Peer Review Findings*

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| | | LOCA size ranges (i.e., the 13.5" break). Available MAAP runs listed in the memo are for breaks up to 10" diameter. Discussions with FPL personnel identified that the 13.5" size cutoff may have been selected by the IPE contractor during the early stages of the IPE, but a specific basis was not located during the review.<br>For the TPN Medium LOCA, i.e., breaks up to 13.5 inches, the PRA assumes that a single train of high head injection can mitigate this class of LOCAs, whereas typical PRAs would instead tend to credit a single train of low head injection for breaks at the upper end of this size range (i.e., above 6").<br>As noted above, analyses supporting the upper end of the Medium LOCA range with this success criterion were not available during the peer review.<br>MAAP 3.0b analyses were used to support the definition of ECCS requirements for the MLOCA, even at the upper end of the break size range (i.e., 13 inches). In general, MAAP 3.0b is not appropriate for rapid depressurizations as would be occurring for breaks in the MLOCA size range. | analyses against results obtained using currently available versions of MAAP, which have improved capabilities for modeling depressurization and other T/H phenomena. | |
| TH-5 | WOG 2002 | The Accident Sequence Notebook indicates that core damage is defined, for referenced | Revise the discussion of core damage conditions | The new Success Criteria Calculation (PTN-BFJR-08-014, Rev. 0) and the updated Revision 8 PTN PRA |

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| | | design-basis analyses, as 2200 degF peak fuel clad temperature. No discussion is provided regarding the core damage criterion for analyses performed using MAAP, but it appears, from the available summary of MAAP runs performed for the IPE, that it was assumed that core damage would occur as soon as core uncovery was predicted by the code.<br>These definitions are reasonable but conservative (i.e., pessimistic) from a PRA perspective. The following observations are noted.<br>The selected core damage criteria can be considered to be functions of the accuracy of the code and model being used to calculate them. For example, supporting requirement SC-A2 of Rev. 14 of the ASME PRA Standard provides example measures of core damage that indicate that 2200 degF would be appropriate using a code with "detailed core modeling" whereas a lower temperature (e.g., 1800 degF) would be more appropriate using a code with "simplified (e.g., single node core model, lumped parameter) core modeling". The idea is to provide sufficient margin between actual and code-calculated values to allow for limitations in codes and models, and | and rationale to address the capabilities of the codes and models used. Consider checking to see that the success criteria would not change significantly if existing conservatisms were removed from the model. | model (PTN-BFJR-00-001, Rev. 9) define 1% clad damage as the core damage end state. |

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| | | uncertainties in inputs and calculations. So, for those PRA success criteria for which the licensing basis analyses provide the success criteria bases, the 2200 degF value is appropriate. Where the MAAP code (or other codes / models with more simplified modeling detail than the licensing basis codes) is used, selection of a lower predicted temperature may be more appropriate.<br>If core uncovery has been used as the core damage criterion in the available Turkey Point MAAP analyses, it is possible that some scenarios for which success credit was not taken may in fact be successful. This is because in some events there may be a brief uncovery of the top of the core without gross fuel heatup, followed by refilling of the vessel as injection occurs. Thus, some PRAs apply a combined temperature and onset of core uncovery, or temperature and time, criterion. It is not possible to determine from the available MAAP 3b analysis summary which cases might change, but the breaks in the S2 size range represent a set of cases where additional investigation might change requirements. Other criteria that could be examined include human action timing. | | |

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| | | Consideration could also be given to demonstrating the viability of secondary side cooldown and depressurization to allow injection via the RHR or charging pumps for sequences with failure of the high head pumps.<br>It is also important that the events being modeled are within the capability of the code used. In the case of the MAAP code, recent versions (e.g., MAAP 4 and later) have enhanced capabilities relative to MAAP 3b for many events modeled in the PRA. | | |
| TH-6 | WOG 2002 | The selection of analytical bases for success criteria, and the MAAP analyses performed for the IPE are documented only in two internal memos (FRN-89-1010, November 1989, and NF-90-450, October 1990). The 1989 memo documents results of a review of available WCAPs to determine timing and other T/H bases for the IPE, but the conclusions reached there appear to have mainly been superceded by the information in the 1990 memo. The 1990 memo provides only tabular summary of results of the various MAAP cases performed, and provides no reference for a verified MAAP base deck, check of input parameters, etc. | Consider developing a process for documenting PRA supporting analyses, including guidance regarding consistent information (inputs, outputs, dicussion/interpretation of results), and implementing this for future analyses.<br>Consider having the MAAP analyst re-document the available analysis information (per the above-referenced memos) | The new Success Criteria Calculation (PTN-BFJR-08-014, Rev. 0) and the updated Revision 8 PTN PRA model (PTN-BFJR-00-001, Rev, 8) resolve this F&O. |

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| | | The memo also does not provide any discussion of how the results should be or were interpreted. Per discussions with the FPL analyst who performed the MAAP analyses (and who authored the memos), there was a preliminary analysis calc prepared for the MAAP analyses, but this was not reviewed/approved, since there were no procedural requirements at the time to do so. Thus, there is no clear documentation of a verified analysis basis for key PRA success criteria, beyond the summary information provided in the memos. | in a current calc, adding best-available information (e.g., by capturing analyst recollections) regarding how the results were interpeted and implemented in the PRA. | |
| HR-A2-01 | FPR 2010 | This HR requires identification, through a review of procedures and practices, those calibration activities that if performed incorrectly can have an adverse impact on the automatic initiation of standby safety equipment.. The system notebooks contain a detailed listing of testing and maintenance procedures that were identified for each system, but there is no discussion as to which procedures were determined to have the potential to result in equipment being left in a miscalibrated condition, and which were screened from consideration with the basis for screening. | A review of the procedures listed in the system notebooks should be performed to identify those that could result in potential miscalibration events, and provide a justification for those that were excluded from further consideration. For miscalibrations that have the potential to impact multiple systems, ensure that they are treated | Rather than examine all possible maintenance, surveillance, and calibration procedures and associated practices, a more practical method was used which presumed that pre-initiators can potentially exist for all redundant standby trains modeled in the PRA and to insert screening values for their probability of occurrence. If quantification of the model with the screening values demonstrates that they are risk significant contributors (FV>0.005), then a specific review of potential maintenance, surveillance, and calibration procedures and practices that could cause the pre initiator condition to exist is performed against the screening rules in HR B1. Any procedures that meet this criterion are identified and |

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| | | | consistently between both systems, and that appropriate HFEs are listed in all impacted system notebooks.<br><br>Similar traceability needs to be provided for other Test and Maintenance procedures that have the ability to render a system/equipment unavailable as well. | documented in the HRA Calculator file.<br>HR-A1 presumes that EVERY possible procedure or practice that could cause misalignment or miscalibration are identified before any screening of events can occur. Further, review of Table 7 revealed that only 2 of the 9 calibration procedures required pre-initiator events for the PRA model, and the events were already in the model. |
| HR-B2-01 | FPR 2010 | This SR does not allow screening of activities that could simultaneously have an impact on multiple trains of a redundant system or diverse system. | Review the actual test and maintenance procedures associated with these valves and determine when they can be subject to testing or maintenance. If they can be subject to testing or maintenance when either of the Units is shutdown, then a T&M needs to be added into the model as well as consideration for a pre-initiator misalignment of the valves, and a post- | Verify assumption in HHSI system notebook. If any of these valves are rendered unavailable for maintenance during power operation, add appropriate T&M events and pre-initiators.<br><br>For the 864 valves, the model has a T&M event for each RWST to account for the time the RWST contents are used to fill the refueling canal, which is probably the only time the 864 valves could be maintained. The RWST T&M event should be a palatable substitute.<br><br>The 845 and 882 valves are locked-open manual valves, so no T&M or pre-initiator is needed there.<br><br>The HHSI recirculation valves 856 and 874C, if closed |

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| | | | initiator HRA to re-align if necessary. | for maintenance take out their related HHSI pumps. The 856 valves are stroke-tested during the associated unit refueling outages. Evaluated pre-initiators for the 856 valves and added these to the model.<br><br>The 878A and 878B valves, if closed for maintenance, would prevent opposite-unit SI. Evaluated pre-initiators for the 878 valves and added these to the model.<br><br>The 856 valves are stroke-tested during the associated unit refueling outages. Evaluated pre-initiators for the 856 valves and added these to the model.<br><br>Ran quantification of the U3 and U4 models with these pre-initiators added - negligible effect on CDF and LERF. |
| HR-C2-01 | FPR 2010 | There is no provided documentation of the plant-specific or applicable generic operating experience for equipment left unavailable for response in accident sequences. | Provide documentation of the review of plant-specific or generic operating experience and confirm that no additional failure mode is required. | In the latest data update, documented in PTN-BFJR-02-026, Rev. 1, condition reports were reviewed for the time period 1992-2006 for component failures. No failure modes outside the ones already modeled were found. |
| HR-D1-01 | FPR 2010 | The human failure event probabilities appear to be evaluated with a systematic process that includes an initial screening value and the identification of risk- | Review and ensure consistency on the calculation of HFE for all pre-initiator and post- | The only thing that needs to be fixed for this finding is Table 3 in the 09-12, Rev. 1 calc. The probabilities for AHFA0N2BK1, AHFA0N2BK1U4, AHFA0N2BK2, and AHFA0N2BK2U4 need to be changed to 4.0E-05, |

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| | | significant action for which a detailed analysis through ASEP method is used. Although there appear to be some inconsistencies in the values of the HEF, especially for HEF already existing in previous version of the model. For example, action AHFA0N2BK1 is indicated as a pre-existing action (i.e., not highlighted in Table 3, page 22) with an initial value of 1.10E-3. There is no further discussion of this action (i.e., the action is not indicated in Table 4 at page 27 as one of the action requiring further analysis). Still in Table 5 at page 31 the action has a value of 4.5E-5 (consistently with what is in the model). Another example of inconsistency between the documentation, the HRA Calculator file and the CAFTA model is post-initiator action AHFPAFWTHROT). | initiator HFEs. | matching the probabilities in Table 5 and the PRA model.<br>The probabilities for AHFA0N2BKU and AHFA0N2BKUU4 need to be changed to 3.6E-05, matching the probabilities in Table 5 and the PRA model.<br>The manner in which these pre-initiators are calculated is documented in the HRA Calculator file used and referenced in calculation PTN-BFJR-09-011, Rev. 1.<br><br>Only the tables, not the model, need to be changed. |
| HR-D3-01 | FPR 2010 | The pre-initiator HRA does not specifically discuss quality of the written procedures or the quality of the human-machine interface. | To achieve CCII/III, a discussion of the quality of procedures and human-machine interface need to be provided. | For each pre-initiator analyzed in detail in the HRA Calculator, there is an assessment of the quality of the procedures and human interface in Performance Shaping Factors. |
| HR-G7-01 | FPR 2010 | This SR outlines the requirements for assessing the degree of dependence between HEPs contained in a single | Review the cutsets associated with Dual-Unit initiating events, and take | The fatigue rule has forced the site into a 4th RO on shift. Attachment 1 of the Ops Dept Instruction ODI-CO-045, Shift Staffing and Accountabilities, 12/21/09 |

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| | | accident sequence or cutset, and accounting for the influence of success or failure in preceding human actions and system performance on the HEP under consideration, including consideration of 1) time required to complete all actions in relation to the time available, 2) factors that could lead to dependence including common instrumentation, procedures, increased stress levels, etc., and 3) availability of resources (e.g. personnel). | into consideration the fact that only 1 of the 2 Units will have 2 Reactor Operators available, or that each Unit may have a single dedicated RO, and a shared RO, and determine the impact of this resource limitation on the HEP. This review should include ALL dual Unit initiating events that credit any post-initiator actions, not only those with multiple actions since the Initiating Event itself creates the dependency concern. | has to be filled out by the Field Supervisor for all of the bargaining unit operators to ensure all of the required positions are covered. Note that there is a fourth RCO position that they have to fill now. That should give you what you need to show 2 RCOs per unit on shift. The ADMs on the subject have been changed as well to account for assignment of the 4th RCO, but they have been carefully worded not to contradict Tech Specs which only requires three...even though the attached ODI-CO-045 is what they actually use to make sure all of the shift assignments are covered. |
| IFPP-B3-01 | FPR 2010 | This SR requires that an uncertainty assessment be included in the documentation. | PTN should perform an uncertainty assessment and document the assessment. | The documentation of the internal flooding analysis now includes a section on uncertainty analysis. |
| IFQU-A1-01 | FPR 2010 | This SR states: For each flood scenario, REVIEW the accident sequences for the associated plant-initiating event group to confirm applicability of the accident sequence model. If appropriate accident sequences do not exist, MODIFY sequences | A review of the accident sequences and quantification results should be documented. | ADD to section 4.2 ...as a result of flooding. "It should be noted that the accidents sequences defined in the internal events model were used to quantify internal flooding scenarios. Each scenario description identifies the existing initiating event to which it is mapped. No new sequences or fault tree models were required." |

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| | | as necessary to account for any unique flood-induced scenarios and/or phenomena in accordance with the applicable requirements described in paragraph 4.5.2. | | Section 4.2.3.1 specifically discusses main steam and feed line breaks as being explicitly addressed in the PRA. Add to end of Section 4.2.3.1 - "This scenario is not considered further because it is already modeled in the PRA." |
| IFQU-A5-01 | FPR 2010 | No human failure event discussion is presented in the analysis. | The documentation of human failure events included in the analysis should be provided. Additionally, the scenario specific impact on PSFs should be documented in the analysis. | No HFE discussion because no credit was taken for mitigating operator actions. Added to Section 3.1.2, paragraph 6 -at specific times are noted. "These times are noted only to highlight the differences in time pressures between flood scenarios. No credit is taken for operator actions that would mitigate any leak, spray, or rupture. Subsequently, no human reliability analysis was necessary."<br>Deleted - "Subsequently, human reliability analysis was applied in quantifying certain accident scenarios when the early termination of the release is to be considered so as to estimate the probabilities that a release would not be terminated before certain damage occurred."<br><br>As for the HFEs from the internal events analysis, the documentation of the internal flooding HRA is included in the calculation PTN-BFJR-11-010, Rev. 0, which is referenced in the internal flooding analysis calculation PTN-BFJR-11-009, Rev. 0. |
| IFQU-A7-01 | FPR 2010 | This SR states: PERFORM internal flood sequence quantification in accordance with | The quantification process should either be | The quantification is discussed in Section 4.3 of calculation PTN-BFJR-11-009, Rev. 0. |

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| | | the applicable requirements described in paragraph 4.5.8. | documented in the flooding analysis, or if the same process has been used elsewhere, the flooding analysis should point to that process. Additionally a review of the quantification should be documented. | |
| IFSN-A11-01 | FPR 2010 | This SR states: For multi-unit sites with shared systems or structures, INCLUDE multi-unit scenarios. | While PTN may not be particularly vulnerable to multi-unit impacts, such impacts need to be discussed in the documentation. If there are no shared systems or structures, this needs to be explicitly stated in the analysis. | Dual-unit impacts are discussed where applicable in individual flood scenarios. The effects of these are automatically accounted for because the Unit 3 and Unit 4 models are linked. |
| IFSN-A16-01 | FPR 2010 | This SR provides the criteria under which human mitigative actions can be credited. | Documentation should be provided which details the human action being credited, and the basis for why they are valid for the scenarios under which they are credited. | As already mentioned in the response for IFQU-A5, no credit is taken for mitigating actions. The times at which various equipment fail in each scenario do not imply an end to the scenario. |

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| IFSN-A2-01 | FPR 2010 | No identification of flood alarms or floor drains has been made in the flood analysis document. | PTN should document and identify the presence of flood alarms and floor drains as related to their treatment in the analysis. | See response for IFQU-A5 - No credit taken for operator action to mitigate flood; therefore, there was no need to credit flood alarms.<br><br>Add to end of Section 3.1.3 - "In looking at flood propagation by backflow through shared drain lines, no credit was taken for check valves."<br><br>Drain lines were not credited in determining the impact of a flood in a particular room. |
| IFSN-A3-01 | FPR 2010 | This SR states: for each defined flood area and each flood source, IDENTIFY those automatic or operator responses that have the ability to terminate or contain the flood propagation. | PTN should identify responses which have the ability to terminate or contain flood propagation, and provide a justification for the timing used in the analysis | As already mentioned in the response for IFQU-A5-01, no credit is taken for mitigative actions. |
| IFSN-A4-01 | FPR 2010 | No supporting information has been provided to justify the estimations regarding flood volumes and the subsequent flooding height. | PTN should document the calculations performed in determining flood volumes in a given flood area as it relates to equipment in the room (the floor area the equipment takes up), the capacity of the system, the length of time the flood persists, etc. | The flooding calculations were added to the notebook along with added discussion in Section 3.2. |

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| IFSN-A6-01 | FPR 2010 | This SR States: For the SSCs identified in IF-C2c, IDENTIFY the susceptibility of each SSC in a flood area to flood-induced failure mechanisms.<br>INCLUDE failure by submergence and spray in the identification process.<br>EITHER:<br>a) ASSESS qualitatively the impact of flood-induced mechanisms that are not formally addressed (e.g., using the mechanisms listed under Capability Category III of this requirement), by using conservative assumptions; OR<br>b) NOTE that these mechanisms are not included in the scope of the evaluation.<br>No discussion has been provided for the impact due to the additional flood failure mechanisms. | Analysis should be performed which includes failure by submergence or spray, and a qualitative assessment of other failure mechanisms needs to be provided (e.g. jet impingement, pipe whip, humidity, condensation, temperature concerns, and any other identified failure modes in the identification process.) Note that the qualitative assessment is a requirement of the NRC Clarification of this SR. | Added to section 3.1.2, paragraph 5 end - "In light of this, it should be noted that only spray and submergence damage were included in the scope of this evaluation." |
| IFSN-A8-01 | FPR 2010 | This SR states: IDENTIFY inter-area propagation through the normal flow path from one area to another via drain lines; and areas connected via back flow through drain lines involving failed check valves, pipe and cable penetrations (including cable trays), doors, stairwells, hatchways, and HVAC ducts. INCLUDE potential for structural failure (e.g., of doors or walls) due to flooding loads. | Documentation of less obvious possible propagation pathways needs to be addressed. | Appendix B includes this info already. Added to Section 3.1.3 - "These pathways are listed in Appendix B under the 'Drainage' section of each zone." |

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| IFSO-A1-01 | FPR 2010 | Based on a confirmatory walkdown performed the Peer Review Team, the locations/impacts of some pipes containing water may have been overlooked in the analysis. | It is recommended that the analyst ensures that spacial information be captured appropriately for spray concerns. Equipment has been identified in walkdown sheets for elevation, but not spatial location. Additionally the analyst should ensure that all potential fluid sources in a given flood area are identified, and all potentially impacted equipment is identified the impact of it failing is evaluated. | The chilled water system operates at very low pressure and the lines are insulated, precluding the possibility of a spray. This information was added to the scenario description. |
| IFSO-A3-01 | FPR 2010 | No process by which screening was performed is present in the analysis. | PTN should document justification for screening particular flood areas from further analysis. | As mentioned in IFPP-B1, no screening was performed, all areas were considered. |
| IFSO-A4-01 | FPR 2010 | No human-induced mechanisms have been included in the analysis, and additionally, no process which justifies their exclusion was provided. | It is identified that tank overfills will relief to vents, drains or the waste disposal system but it is recommended that specific instances be discussed as it | As mentioned in Section 3.1.2, human-induced mechanisms are already taken into account in the general failure data. |

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| | | | relates specifically to operator induced failures. Additionally, a process or program should be identified which prevents human-induced floods from occur, thereby justifying their exclusion from the analysis. | |
| IFSO-A5-01 | FPR 2010 | No summary or characterization of flood sources included in the analysis has been provided. It is difficult to tell what the decisions making up the source characterization were. | Characterize flood sources in terms of capacity, flow rate, pressure, temperature, etc. Additionally, document the justification for a given flow rate. PTN should also document the process used to identify potential flood sources. | The flooding calculations were added to the notebook along with added discussion in Section 3.2. |
| DA-D5-01 | FPR 2013 | For several CCF groups, a "global common cause event" (as described at the end of Section 4.2 of PTN-BFJR-2008-012, Rev. 0) is used. While this is a reasonable simplification, the global common cause event needs to account for the common cause combinations that are not included explicitly. However, for several 6- | Two alternatives. The missing CCF terms could be added to the CAFTA fault trees and CCF basic events calculated for the new terms. A simpler alternative is to revise the calculation of the α6 term | Could not find guidance regarding adding α5 to α6 to approximate the 5/6 combinations in INEL-94/0064, but it makes sense. Does the reviewer have a specific reference (document and page number) for this? |

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| | | component groups (AFW AOVs FTO, AFW CVs FTO, AFW MOVs FTO), the 5-of-6 term was not included and the 6-of-6 term was not adjusted. A similar issue appears to be present for SG SVs FTO (4-component group), where only the 4-of-4 term is included (the 2-of-4 and 3-of-4 terms are missing and the 4-of-4 term was not adjusted). | to include the missing α5 value. Thus, α6' = α5 + α6. This overestimates the a5 contribution, since it is applied to the case where all 6 components fail, but this should be a small and conservative approximation. (Similar correction for the 4-component group, α4' = α2 + α3 + α4). | |
| DA-D6-01 | FPR 2013 | The CCF notebook did not include a review of plant failure data for common cause events. | Review plant-specific component failure events from the most recent data update to identify any common cause failures. If CCFs are identified, verify that the CCF is modeled for the specific component and failure mode. If this data indicates a significantly larger fraction of failures are CCFs than the generic CCF parameters would predict, plant-specific CCF parameters should be | This needs to be done to meet the Standard, but I don't expect to find any plant-specific CCFs. |

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| | | | calculated. If the data is limited (one or two failures in a specific component group), this would not be sufficient evidence to justify plant-specific CCF parameters. | |
| DA-D6-02 | FPR 2013 | Section 3.0 of the CCF Notebook includes the assumption that CCFs are not included in fault tree initiating events with year-long mission times due to excessive conservatism in applying CCF factors that are developed for 24-hr mission time. However, this is not sufficient basis for excluding CCFs for fault tree IE models. | Provide a basis for excluding CCFs from system initiating events and include CCFs where a basis for exclusion cannot be established. For example, include CCF in system initiating event models only for active components that are in the same configuration (i.e., between normally operating pumps in the same system but not between operating and standby pumps in the same system). | CCFs are included for the components in the initiating event fault trees. For example, in the CCW system where 2/3 pumps are normally running, there are AND gates with a single FTR event of one of the normally running pumps with an 8760-hour mission time and CCF events for the other 2 running pumps with mission times equal to the MTR of the pumps. There is not a CCF for all 3 pumps with a mission time of 8760 hours, nor should there be; all 3 pumps are not normally running at the same time, and certainly not for 8760 hours. |
| IE-C14-01 | FPR 2013 | RCP TBHX rupture probability - The IE frequency for tube rupture is based on a Reference 5 value of 3.48E-08/hr (peer | Assess the tube rupture original source data and whether it is applicable to | Will assess. |

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This table summarizes facts and observations with significance ranking "A" or "B" from the 2002 global peer review and the findings from the 2010 and 2013 focused peer reviews.

| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
|---|---|---|---|---|
| | | review did not verify this reference) for "HX Tube External Leak Large >50 gpm". This hourly frequency is multiplied by 8760hr/yr for an annual IE frequency of 3.05E-04/yr. Depending on the application of the data, this IE frequency could be applied at each RCP, thus event tree top event "RCP TBHX Tubes Intact?" would be multiplied by a factor of 3. Applicability of the TBHX data to one or all RCPs should be examined/documented for impact on the total %ZZISLTBCCW initiator/results. | each thermal barrier cooler/RCP. Revise initiator %ZZISLTBCCW and document any changes or basis accordingly. | |
| IE-C14-02 | FPR 2013 | Manual operator action is credited for local manual closure of MOV-*-626 (should it fail to close) and/or to local closure of manual valve *-736. Operator success ensures that the CCW piping remains intact. Although the HEP for the local action is 0.5, the time window basis should document to ensure that the operator has sufficient time to perform these actions before the CCW piping boundary fails. | Evaluate and document whether the operator action should be credited and remove credit for the action if it cannot be justified | The fact that the pressure increase in the CCW system due to the TBHX tube rupture would be mitigated by the CCW surge tank expansion volume and the relief valve RV-3/4-707 opening at 50 pisg are obviously the reason some credit is given to closing a valve to isolate the leak. The time available for performing the isolation will depend upon the size of the rupture as well as other factors. Need to find Westinghouse letter FPL 88-757. Since the HEP is already high at 0.5, this may be more trouble than it's worth. |
| IE-C14-03 | FPR 2013 | Thermal Barrier ISLOCA IE Frequency – RCP Thermal Barrier CCW Supply Penetration #3 - This penetration is not evaluated for potential ISLOCA contribution. This penetration is protected by two normally | Evaluate and document the TBCCW supply penetration for possible ISLOCA initiating events. Should also assess the impact on | Will examine these penetrations for ISLOCA potential. |

## *Enclosure - Peer Review Findings*

This table summarizes facts and observations with significance ranking "A" or "B" from the 2002 global peer review and the findings from the 2010 and 2013 focused peer reviews.

| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
|---|---|---|---|---|
| | | open, active check valves (717 and 721A/B/C) inside containment and two normally open MOVs (716A/B) outside containment. The associated piping inside containment appears to be designed for full RCS pressure. However, given a thermal barrier tube breach, the active check valves could fail to close (w/CCF). The active failure of the outboard MOVs (also w/CCF) may be highly unreliable due to low differential pressure design capability and lack of relevant closure signals, and there might not be sufficient time for manual action. Failure of this penetration should be assessed for possible contribution to the TBCCW ISLOCA event frequency and sequences. | CCW return line from RCP motor cooling and lifting of RV-729 if V-712A fails open. Ensure that these penetrations are also identified in Table 1, list of penetrations. | |
| IE-C14-04 | FPR 2013 | ISLOCA assessment of Penetration 1 (RHR SDC suction line) did not consider that the common suction piping beyond the RHR pumps could be affected by the over-pressurization event. This would impact the function of the high head SI pumps and the RWST (and Containment Spray pumps, which are not important in ISLOCA scenarios). As a result, the current RHR small ISLOCA event sequences apply too much credit for the associated Unit's RWST | Evaluate and document the RHR small ISLOCA sequences taking no credit for associated Unit HHSI pumps and RWST. | Good catch. Will be making this change. |

## *Enclosure - Peer Review Findings*

This table summarizes facts and observations with significance ranking "A" or "B" from the 2002 global peer review and the findings from the 2010 and 2013 focused peer reviews.

| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
|---|---|---|---|---|
| | | and HHSI pumps. | | |
| IE-C14-05 | FPR 2013 | Penetrations 58/59/60: (HHSI cold leg injection) - These penetrations are qualitatively screened from further detailed evaluation on the basis that ...."the combination of three check valves is equivalent to three locked/closed isolation valves", for meeting NUREG/CR-5928 criterion (c), systems isolated by redundant normally closed and locked manual valves that are independently verified to be closed and locked before plant startup". This comment is also applicable to Penetration 18. Additional basis is needed to support this equivalency assertion for screening these penetrations. | Review these penetrations and provide further basis for screening. | I assume the issue here is that 3 closed check valves are not believed to be equivalent to 3 manually isolated manual valves. Still, the probability of 3 closed check valves opening against pressure is likely to be adequately low for screening. |
| IE-C14-06 | FPR 2013 | Suggestion.<br>The PTN ISLOCA analysis is based on early NUREG information and industry practice, which continue to provide a reasonable source of inputs/practice for consideration in ISLOCA modeling. In general however, the evaluation might benefit from aspects of the latest industry ISLOCA best practice/methodology presented in WCAP-17154, Rev.1. | Consider updating the ISLOCA evaluation to current industry practice and reference material. It is noted that there are limitations in the WCAP-17154, Revision 1 methodology and its complete adoption is not recommended. | Will likely update the ISLOCA model with the benefit of the latest guidance when resources permit. |

## *Enclosure - Peer Review Findings*

This table summarizes facts and observations with significance ranking "A" or "B" from the 2002 global peer review and the findings from the 2010 and 2013 focused peer reviews.

| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
|---|---|---|---|---|
| IE-C14-07 | FPR 2013 | Suggestion.<br><br>Table 1 "Potential ISLOCA Flow Paths" - Consider adding more detail in the ISL Screening Results column. For example, Penetrations 13 and 14 (Letdown and Charging) may not cleanly screen. Both systems interface with low pressure systems (letdown-purification piping and charging-pump suction). Typically there are redundant isolation means to isolate - thus IE frequency should be low. However, this cannot be concluded from the table details. Also, Penetration 3, "RCP CCW Supply" indicates that this penetration was screened based on "not connected to the RCS". However, this penetration provides the CCW supply to RCP thermal barrier cooling and should be assessed (refer to F&O IE-C14-2). | Consider updating the ISLOCA report to improve the details in Table 1, primarily the column information under "ISL Screening Results" | OK. |
| LE-D2-01 | FPR 2013 | Electrical penetration assembly failure modes have been found to be important contributors to overall containment fragility at other large dry PWRs, and in at least 2 instances, tend to be the most limiting in terms of ultimate failure pressure. Additionally, early studies at Sandia National Laboratories have considered the potential impact of very high (beyond | Perform a scoping assessment of the potential impact of electrical penetration thermal-mechanical response to severe accidents. Consider using some of the following references: NUREG/CR- | For containment isolation, the Level 2 update incorporated the existing containment isolation analysis; it did not revisit this issue directly. As for containment strength, this was also something that was provided and was not re-investigated, so would not have affected the analysis directly. The place in the Level 2 model where this would have an effect would be the "Containment Failure at Vessel Breach" events, which were determined via NUREG sources to |

## *Enclosure - Peer Review Findings*

This table summarizes facts and observations with significance ranking "A" or "B" from the 2002 global peer review and the findings from the 2010 and 2013 focused peer reviews.

| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
|---|---|---|---|---|
| | | design basis) temperatures on elastomer seals (this latter issue is more critical for small volume containments such as BWR Mark I). | 4944, CR-5083, CR-5096, CR-5118, and CR-5334. | be minimal. It is not known whether these referenced NUREGs already factored such considerations into their containment strength estimates and failure probabilities, but it is not expected to have a significant effect. |
| LE-F1-01 | FPR 2013 | Endstate frequency totals are given in Table 5 of the Level 2 notebook, PTN-BJFR-99-010, Rev. 1, and results by release category are given in Table 6. However, results using the Plant Damage State definitions of Section 4.2 are not provided. CC II is not met because relative contribution to LERF by PDS is not shown, although information is available to provide such data. | Perform summary calculation to quantify PDS relative contribution to LERF. | Will add to update calculations. |
| LE-G5-01 | FPR 2013 | There is no discussion of limitations of severe accident understanding and modeling. This includes such matters as the impact of uncertainty regarding thermally induced SGTR on quantification, the uncertainty of ISLOCA break size and location on timing and source term, and the assignment of CET to endstates. Conservative treatment of some phenomena can affect LERF quantification, which in turn impacts LERF and delta LERF results when applying RG 1.174 guidelines in risk-informed changes to the licensing | Provide a discussion of possible limitations of the LERF analysis based on, for example, limitations on the state of severe accident understanding and level 2 PRA analysis. Briefly describe how key uncertainties in the LERF quantification could impact risk-informed changes to the licensing basis under RG 1.174, for example. | Will add discussion. |

## *Enclosure - Peer Review Findings*

This table summarizes facts and observations with significance ranking "A" or "B" from the 2002 global peer review and the findings from the 2010 and 2013 focused peer reviews.

| F&O # | Peer Review | Description | Possible Resolution | Plant Response or Resolution |
|---|---|---|---|---|
| | | basis, for example. | | |

# Attachment 3

## Turkey Point Nuclear Plant
## License Amendment Request No. LAR-229

## Technical Specifications
## Marked-Up Pages

**This coversheet plus 105 pages.**

**Turkey Point Nuclear Plant
Units 3 and 4
Technical Specifications
Marked-Up Pages**

**List of Affected Pages**

| | | | | | | |
|---|---|---|---|---|---|---|
| 3/4 1-1 | 3/4 2-6 | 3/4 3-34 | 3/4 4-20 | 3/4 6-7 | 3/4 7-12 | 3/4 8-23 |
| 3/4 1-2 | 3/4 2-7 | 3/4 3-38 | 3/4 4-25 | 3/4 6-11 | 3/4 7-13 | 3/4 9-1 |
| 3/4 1-4 | 3/4 2-8 | 3/4 3-39 | 3/4 4-28 | 3/4 6-12 | 3/4 7-14 | 3/4 9-2 |
| 3/4 1-8 | 3/4 2-12 | 3/4 3-40 | 3/4 4-37 | 3/4 6-13 | 3/4 7-15 | 3/4 9-8 |
| 3/4 1-10 | 3/4 2-15 | 3/4 3-46 | 3/4 4-39 | 3/4 6-14 | 3/4 7-16b | 3/4 9-9 |
| 3/4 1-12 | 3/4 2-16 | 3/4 3-49 | 3/4 5-1 | 3/4 6-15 | 3/4 7-17 | 3/4 9-12 |
| 3/4 1-15 | 3/4 3-8 | 3/4 4-1 | 3/4 5-2 | 3/4 6-18 | 3/4 7-22 | 3/4 9-15 |
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| 3/4 1-21 | 3/4 3-10 | 3/4 4-4 | 3/4 5-7 | 3/4 7-4 | 3/4 8-5 | 6-18c |
| 3/4 1-22 | 3/4 3-31a | 3/4 4-5 | 3/4 5-8 | 3/4 7-7 | 3/4 8-6 | |
| 3/4 1-23 | 3/4 3-32 | 3/4 4-6 | 3/4 5-10 | 3/4 7-9 | 3/4 8-9 | |
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**List of Pages for Information Only**

| | | |
|---|---|---|
| 3/4 3-1 | 3/4 3-47 | 3/4 8-7 |
| 3/4 3-13 | 3/4 4-23 | 3/4 8-8 |
| 3/4 3-35 | 3/4 4-26 | |
| 3/4 3-41 | 3/4 7-8 | |

**Insert 1**

| |
|---|
| Note that Insert 1 capitalization and punctuation is varied based on the use in each specific surveillance requirement. |

In accordance with the Surveillance Frequency Control Program.

**Insert 2**

I. Surveillance Frequency Control Program

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

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

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

c. The provisions of Surveillance Requirements 4.0.2 and 4.0.3 are applicable to the frequencies established in the Surveillance Frequency Control Program.

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 BORATION CONTROL

SHUTDOWN MARGIN - $T_{avg}$ GREATER THAN 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.1 The SHUTDOWN MARGIN shall be within the limits specified in the COLR.

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

ACTION:

With the SHUTDOWN MARGIN not within limits, immediately initiate and continue boration at greater than or equal to 16 gpm of a solution containing greater than or equal to 3.0 wt% (5245 ppm) boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.1.1 The SHUTDOWN MARGIN shall be determined to be within the limits specified in the COLR:

a. Within 1 hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the above required SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s);

b. When in MODE 1 or MODE 2 with $K_{eff}$ greater than or equal to 1 ~~at least once per 12 hours~~ by verifying that control bank withdrawal is within the limits of Specification 3.1.3.6;

c. When in MODE 2 with $K_{eff}$ less than 1, within 4 hours prior to achieving reactor criticality by verifying that the predicted critical control rod position is within the limits of Specification 3.1.3.6;

d. Prior to initial operation above 5% RATED THERMAL POWER after each fuel loading, by consideration of the factors of Specification 4.1.1.1.1e. below, with the control banks at the maximum insertion limit of Specification 3.1.3.6; and

Insert 1

*See Special Test Exceptions Specification 3.10.1.

SURVEILLANCE REQUIREMENTS (Continued)

In accordance with the Surveillance Frequency Control Program, when

e. ~~When~~ in MODE 3 or 4, ~~at least once per 24 hours~~ by consideration of the following factors:

1) Reactor Coolant System boron concentration,

2) Control rod position,

3) Reactor Coolant System average temperature,

4) Fuel burnup based on gross thermal energy generation,

5) Xenon concentration, and

6) Samarium concentration.

Insert 1

4.1.1.1.2 When in Mode 1 or 2, the overall core reactivity balance shall be compared to predicted values to demonstrate agreement within ± 1% $\Delta k/k$ ~~at least once per 31 Effective Full Power Days (EFPD)~~. This comparison shall consider at least those factors stated in Specification 4.1.1.1.1e, above. The predicted reactivity values shall be adjusted (normalized) to correspond to the actual core conditions prior to exceeding a fuel burnup of 60 EFPD after each fuel loading.

SHUTDOWN MARGIN - $T_{avg}$ LESS THAN OR EQUAL TO 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.2 The SHUTDOWN MARGIN shall be within the limit specified in the COLR.

APPLICABILITY: MODE 5.

ACTION:

With the SHUTDOWN MARGIN not within limits, immediately initiate and continue boration at greater than or equal to 16 gpm of a solution containing greater than or equal to 3.0 wt% (5245 ppm) boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN shall be determined to be within the limit specified in the COLR:

a. Within 1 hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s); and

b. ~~At least once per 24 hours~~ by consideration of the following factors:

Insert 1

1) Reactor Coolant System boron concentration,

2) Control rod position,

3) Reactor Coolant System average temperature,

4) Fuel burnup based on gross thermal energy generation,

5) Xenon concentration, and

6) Samarium concentration.

## 3/4.1.2 BORATION SYSTEMS

### FLOW PATH - SHUTDOWN

### LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE and capable of being powered from an OPERABLE emergency power source:

a. A flow path from the boric acid storage tanks via a boric acid transfer pump and a charging pump to the Reactor Coolant System if the boric acid storage tank in Specification 3.1.2.4a. is OPERABLE, or

b. The flow path from the refueling water storage tank via a charging pump to the Reactor Coolant System if the refueling water storage tank in Specification 3.1.2.4b. is OPERABLE.

APPLICABILITY: MODES 5 and 6.

ACTION:

With none of the above flow paths OPERABLE or capable of being powered from an OPERABLE emergency power source, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

### SURVEILLANCE REQUIREMENTS

4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that the temperature of the rooms containing flow path components is greater than or equal to 62°F when a flow path from the boric acid tanks is used, and

Insert 1

b. ~~At least once per 31 days~~ by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

SURVEILLANCE REQUIREMENTS

4.1.2.2 The above required flow paths shall be demonstrated OPERABLE:

Insert 1

a. At least once per 7 days by verifying that the temperature of the rooms containing flow path components is greater than or equal to 62°F when a flow path from the boric acid tanks is used; *

b. ~~At least once per 31 days~~ by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position;

c. ~~At least once per 18 months~~ by verifying that the flow path required by Specification 3.1.2.2a. and c. delivers at least 16 gpm to the RCS.

BORATED WATER SOURCE - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.4 As a minimum, one of the following borated water sources shall be OPERABLE:

a. A Boric Acid Storage System with:

1) A minimum indicated borated water volume of 2,900 gallons per unit,

2) A boron concentration between 3.0 wt% (5245 ppm) and 4.0 wt.% (6993 ppm), and *

3) A minimum boric acid tanks room temperature of 62°F. *

b. The refueling water storage tank (RWST) with:

1) A minimum indicated borated water volume of 20,000 gallons,

2) A boron concentration between 2400 ppm and 2600 ppm, and *

3) A minimum solution temperature of 39°F.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no borated water source OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.4 The above required borated water source shall be demonstrated OPERABLE:

a. ~~At least once per 7 days~~ by:

Insert 1

1) Verifying the boron concentration of the water,

2) Verifying the indicated borated water volume, and

3) Verifying that the temperature of the boric acid tanks room is greater than or equal to 62°F, when it is the source of borated water. *

SURVEILLANCE REQUIREMENTS

4.1.2.5 *Each borated water source shall be demonstrated OPERABLE:*

a. ~~At least once per 7 days~~ by:

Insert 1

1) Verifying the boron concentration in the water,

2) Verifying the indicated borated water volume of the water source, and

3) Verifying that the temperature of the boric acid tanks room is greater than or equal to 62°F, when it is the source of borated water.

b. By verifying the RWST temperature is within limits whenever the outside air temperature is less than 39°F or greater than 100°F at the following frequencies:

1) Within one hour upon the outside temperature exceeding its limit for 23 consecutive hours, and

2) At least once per 24 hours while the outside temperature exceeds its limits.

d. With one full length rod inoperable due to causes other than addressed by ACTION a, above, or misaligned from its group step counter demand position by more than the Allowed Rod Misalignment of Specification 3.1.3.1, POWER OPERATION may continue provided that within one hour either:

1. The rod is restored to OPERABLE status within the Allowed Rod Misalignment of Specification 3.1.3.1, or

2. The remainder of the rods in the bank with the inoperable rod are aligned to within the Allowed Rod Misalignment of Specification 3.1.3.1 of the inoperable rod while maintaining the rod sequence and insertion limits of Specification 3.1.3.6; the THERMAL POWER level shall be restricted pursuant to Specification 3.1.3.6 during subsequent operation, or

3. The rod is declared inoperable and the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied. POWER OPERATION may then continue provided that:

a) The THERMAL POWER level is reduced to less than or equal to 75% of RATED THERMAL POWER within one hour and within the next 4 hours the power range neutron flux high trip setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER. THERMAL POWER shall be maintained less than or equal to 75% of RATED THERMAL POWER until compliance with ACTIONS 3.1.3.1.d.3.c and 3.1.3.1.d.3.d below are demonstrated, and

b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours, and

c) A power distribution map is obtained from the movable incore detectors and $F_Q$ (Z) and $F^N_{\Delta H}$ are verified to be within their limits within 72 hours, and

d) A reevaluation of each accident analysis of Table 3.1-1 is performed within 5 days; this reevaluation shall confirm that the previously analyzed results of these accidents remain valid for the duration of operation under these conditions.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The position of each full length rod shall be determined to be within the Allowed Rod Misalignment of the group step counter demand position ~~at least once per 12 hours~~ (allowing for one hour thermal soak after rod motion) except during time intervals when the Rod Position Deviation Monitor is inoperable, then verify the group positions at least once per 4 hours.

4.1.3.1.2 Each full length rod not fully inserted in the core shall be determined to be OPERABLE by movement of at least 10 steps in any one direction ~~at least once per 92 days~~.

Insert 1

## SURVEILLANCE REQUIREMENTS

4.1.3.2.1 Each analog rod position indicator shall be determined to be OPERABLE by verifying that the Demand Position Indication System and the Analog Rod Position Indication System agree within the Allowed Rod Misalignment of Specification 3.1.3.1 (allowing for one hour thermal soak after rod motion) ~~at least once per 12 hours~~ except during time intervals when the Rod Position Deviation Monitor is inoperable, then compare the Demand Position Indication System and the Analog Rod Position Indication System at least once per 4 hours.

4.1.3.2.2 Each of the above required analog rod position indicator(s) shall be determined to be OPERABLE by performance of a CHANNEL CHECK, CHANNEL CALIBRATION and ANALOG CHANNEL OPERATIONAL TEST performed in accordance with Table 4.1-1.

Insert 1

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.1-1

ROD POSITION INDICATOR SURVEILLANCE REQUIREMENTS

| Functional Unit | Check | Calibration | Operational Test |
|---|---|---|---|
| Individual Rod Position | ~~S~~ | ~~R~~ | ~~M~~ |
| Demand Position | ~~S~~ | N/A | ~~R~~ |

REACTIVITY CONTROL SYSTEMS

POSITION INDICATION SYSTEM - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.3.3 The group step counter demand position indicator shall be OPERABLE and capable of determining within ± 2 steps the demand position for each shutdown and control rod not fully inserted.

APPLICABILITY: MODES 3* **, 4* **, and 5* **

ACTION:

With less than the above required group step counter demand position indicator(s) OPERABLE, open the reactor trip system breakers.

SURVEILLANCE REQUIREMENTS

4.1.3.3.1 Each of the above required group step counter demand position indicator(s) shall be determined to be OPERABLE by movement of the associated control rod at least 10 steps in any one direction ~~at least once per 31 days~~. Insert 1

4.1.3.3.2 OPERABILITY of the group step counter demand position indicator shall be verified in accordance with Table 4.1-1.

* With the Reactor Trip System breakers in the closed position.

** See Special Test Exceptions Specification 3.10.5.

REACTIVITY CONTROL SYSTEMS

ROD DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual full-length (shutdown and control) rod drop time from the fully withdrawn position shall be less than or equal to 2.4 seconds from beginning of decay of stationary gripper coil voltage to dashpot entry with:

a. $T_{avg}$ greater than or equal to 500°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 and 2.

ACTION:

With the drop time of any full-length rod determined to exceed the above limit, restore the rod drop time to within the above limit prior to proceeding to MODE 1 or 2.

SURVEILLANCE REQUIREMENTS

4.1.3.4 The rod drop time of full-length rods shall be demonstrated through measurement prior to reactor criticality:

a. For all rods following each removal of the reactor vessel head,

b. For specifically affected individual rods following any maintenance on or modification to the Control Rod Drive System which could affect the drop time of those specific rods, and

c. ~~At least once per 18 months~~.

Insert 1

CONTROL ROD INSERTION LIMITS

LIMITING CONDITION FOR OPERATION

3.1.3.6 The control banks shall be limited in physical insertion specified in the Rod Bank Insertion Limits curve, defined in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: MODES 1* and 2* **

ACTION:

With the control banks inserted beyond the above insertion limits, except for surveillance testing pursuant to Specification 4.1.3.1.2 either:

a. Restore the control banks to within the limits within 2 hours, or

b. Reduce THERMAL POWER within two hours to less than or equal to that fraction of RATED THERMAL POWER which is allowed by the bank position specified in the Rod Bank Insertion Limits curve, defined in the CORE OPERATING LIMITS REPORT, or

c. Be in at least HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.6 The position of each control bank shall be determined to be within the insertion limits ~~at least once per 12 hours~~, except during time intervals when the Rod Insertion Limit Monitor is inoperable, then verify the individual rod positions at least once per 4 hours.

Insert 1

* See Special Test Exceptions Specifications 3.10.2 and 3.10.3.

** With $K_{eff}$ greater than or equal to 1.0

SURVEILLANCE REQUIREMENTS

4.2.1.1 The indicated AFD shall be determined to be within its limits during POWER OPERATION above 50% of RATED THERMAL POWER by:

a. Monitoring the indicated AFD for each OPERABLE excore channel:

1) Insert 1 ~~At least once per 7 days~~ when the alarm used to monitor the AFD is OPERABLE, and

2) At least once per hour for the first 6 hours after restoring the alarm used to monitor the AFD to OPERABLE status.*

b. Monitoring and logging the indicated AFD for each OPERABLE excore channel ~~at least once per~~ hour for the first 24 hours and at least once per 30 minutes thereafter, when the alarm used to monitor the AFD is inoperable. The logged values of the indicated AFD shall be assumed to exist during the interval preceding each logging.

4.2.1.2 Insert 1 The target flux difference of each OPERABLE excore channel shall be determined by measurement ~~at least once per 92 Effective Full Power Days~~. The provisions of Specification 4.0.4 are not applicable.

4.2.1.3 In accordance with the Surveillance Frequency Control Program, the ~~The~~ target flux difference shall be updated ~~at least once per 31 Effective Full Power Days~~ by either determining the target flux difference pursuant to Specification 4.2.1.2 above or by linear interpolation between the most recently measured value and the predicted value at the end of the cycle life. The provisions of Specification 4.0.4 are not applicable.

* Performance of a functional test to demonstrate OPERABILITY of the alarm used to monitor the AFD may be substituted for this requirement.

SURVEILLANCE REQUIREMENTS

4.2.2.1 If $[F_Q]^P$ as predicted by approved physics calculations is greater than $[F_Q]^L$ and P is greater than $P_T$* as defined in 4.2.2.2, $F_Q(Z)$ shall be evaluated by MIDS (Specification 4.2.2.2), BASE LOAD (Specification 4.2.2.3) or RADIAL BURNDOWN (Specification 4.2.2.4) to determine if $F_Q$ is within its limit $[F_Q]^P$ = Predicted $F_Q$).

If $[F_Q]^P$, is less than $[F_Q]^L$ or P is less than $P_T$, $F_Q(Z)$ shall be evaluated to determine if $F_Q(Z)$ is within its limit as follows:

a. Using the movable incore detectors to obtain power distribution map at any THERMAL POWER greater than 5% of RATED THERMAL POWER.

b. Increasing the measured $F_Q(Z)$ component of the power distribution map by 3% to account for manufacturing tolerances and further increasing the value by 5% to account for measurement uncertainties. Verifying that the requirements of Specification 3.2.2 are satisfied.

c. $F_Q^M(Z) \le F_Q^L(Z)$

Where $F_Q^M(Z)$ is the measured $F_Q(Z)$ increased by the allowance for manufacturing tolerances and measurement uncertainty and $F_Q^L(Z)$ is the $F_Q$ limit defined in 3.2.2.

d. Measuring $F_Q^M(Z)$ according to the following schedule:

1. Prior to exceeding 75% of RATED THERMAL POWER,** after refueling,

2. ~~At least once per 31 Effective Full Power Days.~~ Insert 1

e. With the relationship specified in Specification 4.2.2.1.c above not being satisfied:

1) Calculate the percent $F_Q^M(Z)$ exceeds its limit by the following expression:

$$\left[\left[\frac{F_Q^M(Z)}{[F_Q]^L \times K(Z)/P}\right]-1\right] \times 100 \text{ for } P \ge 0.5$$

$$\left[\left[\frac{F_Q^M(Z)}{[F_Q]^L \times K(Z)/0.5}\right]-1\right] \times 100 \text{ for } P < 0.5$$

* $P_T$ = Reactor power level at which predicted $F_Q$ would exceed its limit.

** During power escalation at the beginning of each cycle, power level may be increased until a power level for extended operation has been achieved and power distribution map obtained.

2) The following action shall be taken:

a) Comply with the requirements of Specification 3.2.2 for $F_Q^M(Z)$ exceeding its limit by the percent calculated above.

4.2.2.2 MIDS

Operation is permitted at power above $P_T$ where $P_T$ equals the ratio of $[F_Q]^L$ divided by $[F_Q]^P$ if the following Augmented Surveillance (Movable Incore Detection System, MIDS) requirements are satisfied:

a. The axial power distribution shall be measured by MIDS when required such that the limit of $[F_Q]^L/P$ times K(Z) is not exceeded. $F_j(Z)$ is the normalized axial power distribution from thimble j at core elevation (Z).

1) If $F_j(Z)$ exceeds $[F_j(Z)]_s$* as defined in the bases by ≤ 4%, immediately reduce thermal power one percent for every percent by which $[F_j(Z)]_s$ is exceeded.

2) If $F_j(Z)$ exceeds $[F_j(Z)]_s$ by > 4% immediately reduce thermal power below $P_T$. Corrective action to reduce $F_j(Z)$ below the limit will permit return to thermal power not to exceed current $P_L$** as defined in the bases.

Insert 1

b. $F_j(Z)$ shall be determined to be within limits by using MIDS to monitor the thimbles required per Specification 4.2.2.2.c at the following frequencies.

1. ~~At least once every 24 hours,~~ and

2. Immediately following and as a minimum at 2, 4 and 8 hours following the events listed below and every 24 hours thereafter.

1) Raising the thermal power above $P_T$, or

2) Movement of control-bank D more than an accumulated total of 15 steps in any one direction.

c. MIDS shall be operable when the thermal power exceeds $P_T$ with:

1) At least two thimbles available for which $\overline{R_j}$ and $\sigma_j$ as defined in the bases have been determined.

* $[F_j(Z)]_s$ is the alarm setpoint for MIDS.

** $P_L$ is reactor thermal power expressed as a fraction of the Rated Thermal Power that is used to calculate $[F_j(Z)]_s$.

SURVEILLANCE REQUIREMENTS (Continued)

2. At least two movable detectors available for mapping $F_j(Z)$.

3. The continued accuracy and representativeness of the selected thimbles shall be verified by using the most recent flux map to update the $\bar{R}$ for each selected thimble. The flux map must be updated ~~at least once per 31 effective full power days~~.

Insert 1

where:

$\bar{R}$ = Total peaking factor from a full flux map ratioed to the axial peaking factor in a selected thimble.

j - The thimble location selected for monitoring.

4.2.2.3 Base Load

Base Load operation is permitted at powers above $P_T$ if the following requirements are satisfied:

a. Either of the following preconditions for Base Load operation must be satisfied.

1. For entering Base Load operation with power less than $P_T$,

a) Maintain THERMAL POWER between $P_T/1.05$ and $P_T$ for at least 24 hours,

b) Maintain the AFD (Delta-I) to within a ± 2% or ± 3% target band for at least 23 hours per 24-hour period.

c) After 24 hours have elapsed, take a full core flux map to determine $F_Q^M(Z)$ unless a valid full core flux map was taken within the time period specified in 4.2.2.1d.

d) Calculate $P_{BL}$ per 4.2.2.3b.

2. For entering Base Load operation with power greater than $P_T$,

a) Maintain THERMAL POWER between $P_T$ and the power limit determined in 4.2.2.2 for at least 24 hours, and maintain Augmented Surveillance requirements of 4.2.2.2 during this period.

b) Maintain the AFD (Delta-I) to within a ± 2% or ± 3% target band for at least 23 hours per 24-hour period,

SURVEILLANCE REQUIREMENTS

4.2.3.1 The provisions of Specification 4.0.4 are not applicable.

4.2.3.2 When a measurement of $F^N_{\Delta H}$ is taken, the measured $F^N_{\Delta H}$ shall be increased by 4% to account for measurement error.

4.2.3.3 This corrected $F^N_{\Delta H}$ shall be determined to be within its limit through incore flux mapping:

a. Prior to operation above 75% of RATED THERMAL POWER after each fuel loading, and

b. ~~At least once per 31 Effective Full Power Days~~.

Insert 1

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 2 hours and reduce the Power Range Neutron Flux-High Trip Setpoints to less than or equal to 55% of RATED THERMAL POWER within the next 4 hours; and

3. Identify and correct the cause of the out-of -limit condition prior to increasing THERMAL POWER; subsequent POWER OPERATION above 50% of RATED THERMAL POWER may proceed provided that the QUADRANT POWER TILT RATIO is verified within its limit at least once per hour for 12 hours or until verified at 95% or greater RATED THERMAL POWER.

d. The provisions of Specifications 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.2.4.1 The QUADRANT POWER TILT RATIO shall be determined to be within the limit above 50% of RATED THERMAL POWER ~~by~~:

Insert 1

a. ~~Calculating~~ the ratio ~~at least once per 7 days~~ when the Power Range Upper Detector High Flux Deviation and Power Range Lower Detector High Flux Deviation Alarms are OPERABLE, and

b. ~~Calculating~~ the ratio at least once per 12 hours during steady-state operation when either alarm is inoperable.

By calculating

4.2.4.2 The QUADRANT POWER TILT RATIO shall be determined to be within the limit when above 75% of RATED THERMAL POWER with one Power Range channel inoperable by using the movable incore detectors to confirm that the normalized symmetric power distribution, obtained either from two sets of four symmetric thimble locations or full-core flux map, or by incore thermocouple map is consistent with the indicated QUADRANT POWER TILT RATIO at least once per 12 hours.

4.2.4.3 If the QUADRANT POWER TILT RATIO is not within its limit within 24 hours and the POWER DISTRIBUTION LIMITS of 3.2.2 and 3.2.3 are within their limits, a Special Report in accordance with 6.9.2 shall be submitted within 30 days including an evaluation of the cause of the discrepancy.

In accordance with the Surveillance Frequency Control Program by calculating

POWER DISTRIBUTION LIMITS

3/4.2.5 DNB PARAMETERS

LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB-related parameters shall be maintained within the following limits:

a. Reactor Coolant System $T_{avg}$ is less than or equal to the limit specified in the COLR

b. Pressurizer Pressure is greater than or equal to the limit specified in the COLR*, and

c. Reactor Coolant System Flow ≥ 270,000 gpm *

APPLICABILITY: MODE 1.

ACTION:

With any of the above parameters exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less then 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5.1 Reactor Coolant System $T_{avg}$ and Pressurizer Pressure shall be verified to be within their limits ~~at least once per 12 hours~~.

Insert 1

4.2.5.2 RCS flow rate shall be monitored for degradation ~~at least once per 12 hours~~.

4.2.5.3 The RCS flow rate indicators shall be subjected to a CHANNEL CALIBRATION ~~at least once per 18 months~~.

4.2.5.4 After each fuel loading, and ~~at least once per 18 months,~~ the RCS flow rate shall be determined by precision heat balance after exceeding 90% RATED THERMAL POWER. The measurement instrumentation shall be calibrated within 90 days prior to the performance of the calorimetric flow measurement. The provisions of 4.0.4 are not applicable for performing the precision heat balance flow measurement.

* Limit not applicable during either a THERMAL POWER ramp in excess of 5% of RATED THERMAL POWER per minute or a THERMAL POWER step in excess of 10% of RATED THERMAL POWER.

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## 3/4.3.1 REACTOR TRIP SYSTEM INSTRUMENTATION

### LIMITING CONDITION FOR OPERATION

3.3.1 As a minimum, the Reactor Trip System instrumentation channels and interlocks of Table 3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3-1.

ACTION:

As shown in Table 3.3-1.

### SURVEILLANCE REQUIREMENTS

4.3.1.1 Each Reactor Trip System instrumentation channel and interlock and the automatic trip logic shall be demonstrated OPERABLE by the performance of the Reactor Trip System Instrumentation Surveillance Requirement specified in Table 4.3-1.

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

| FUNCTIONAL UNIT | CHANNEL CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | TRIP ACTUATING DEVICE OPERATIONAL TEST | ACTUATION LOGIC TEST | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|---|---|
| 1. Manual Reactor Trip | N.A. | N.A. | N.A. | ~~R~~(11) | N.A. | 1, 2, 3*, 4*, 5* |
| 2. Power Range, Neutron Flux<br>a. High Setpoint | ~~S~~ | ~~D~~(2, 4),<br>~~M~~(3, 4),<br>~~Q~~(4, 6),[(a), (b)]<br>~~R~~(4)[(a), (b)] | ~~Q~~[(a), (b)] | N.A. | N.A. | 1, 2 |
| b. Low Setpoint | ~~S~~ | ~~R~~(4) | S/U(1) | N.A. | N.A. | 1***, 2 |
| 3. Intermediate Range, Neutron Flux | ~~S~~ | ~~R~~(4) | S/U(1) | N.A. | N.A. | 1***, 2 |
| 4. Source Range, Neutron Flux | ~~S~~ | ~~R~~(4) | S/U(1), ~~Q~~(9) | N.A. | N.A. | 2**,3, 4, 5 |
| 5. Overtemperature ΔT | ~~S~~ | ~~R~~[(a), (b)] | ~~Q~~[(a), (b)] | N.A. | N.A. | 1, 2 |
| 6. Overpower ΔT | ~~S~~ | ~~R~~[(a), (b)] | ~~Q~~[(a), (b)] | N.A. | N.A. | 1, 2 |
| 7. Pressurizer Pressure--Low | ~~S~~ | ~~R~~ | ~~Q~~ | N.A. | N.A. | 1 |
| 8. Pressurizer Pressure--High | ~~S~~ | ~~R~~ | ~~Q~~ | N.A. | N.A. | 1, 2 |
| 9. Pressurizer Water Level--High | ~~S~~ | ~~R~~ | ~~Q~~ | N.A. | N.A. | 1 |
| 10. Reactor Coolant Flow--Low | ~~S~~ | ~~R~~[(a), (b)] | ~~Q~~[(a), (b)] | N.A. | N.A. | 1 |
| 11. Steam Generator Water Level--Low-Low | ~~S~~ | ~~R~~[(a), (b)] | ~~Q~~[(a), (b)] | N.A. | N.A. | 1, 2 |

Replace each marked through Surveillance Frequency with "SFCP".

## TABLE 4.3-1

## REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

| FUNCTIONAL UNIT | CHANNEL CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | TRIP ACTUATING DEVICE OPERATIONAL TEST | ACTUATION LOGIC TEST | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|---|---|
| 12. Steam Generator Water Level--Low Coincident with Steam/Feedwater Flow Mismatch | ~~S~~ | ~~R~~(a), (b) | ~~Q~~(a), (b) | N.A. | N.A. | 1, 2 |
| 13. Undervoltage – 4.16 kV Busses A and B | N.A. | ~~R~~ | N.A. | N.A. | N.A. | 1 |
| 14. Underfrequency – Trip of Reactor Coolant Pump Breakers(s) Open | N.A. | ~~R~~ | N.A. | N.A. | N.A. | 1 |
| 15. Turbine Trip | | | | | | |
| a. Emergency Trip Header Pressure | N.A. | ~~R~~(a), (b) | N.A. | S/U(1, 10) | N.A. | 1 |
| b. Turbine Stop Valve Closure | N.A. | ~~R~~ | N.A. | S/U(1, 10) | N.A. | 1 |
| 16. Safety Injection Input from ESF | N.A. | N.A. | N.A. | ~~R~~ | N.A. | 1, 2 |
| 17. Reactor Trip System Interlocks | | | | | | |
| a. Intermediate Range Neutron Flux, P-6 | N.A. | ~~R~~(4) | ~~R~~ | N.A. | N.A. | 2** |
| b. Low Power Reactor Trips Block, P-7 (includes P-10 input and Turbine Inlet Pressure) | N.A. | ~~R~~(4) | ~~R~~ | N.A. | N.A. | 1 |
| c. Power Range Neutron Flux, P-8 | N.A. | ~~R~~(4) | ~~R~~ | N.A. | N.A. | 1 |

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

| FUNCTIONAL UNIT | CHANNEL CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | TRIP ACTUATING DEVICE OPERATIONAL TEST | ACTUATION LOGIC TEST | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|---|---|
| 17. Reactor Trip System Interlocks (Continued) | | | | | | |
| d. Power Range Neutron Flux, P-10 | N.A. | ~~R~~(4) | ~~R~~ | N.A. | N.A. | 1, 2 |
| 18. Reactor Coolant Pump Breaker Position Trip | N.A. | N.A. | N.A. | ~~R~~ | N.A. | 1 |
| 19. Reactor Trip Breaker | N.A. | N.A. | N.A. | ~~M~~(7, 11) | N.A. | 1, 2, 3*, 4*, 5* |
| 20. Automatic Trip and Interlock Logic | N.A. | N.A. | N.A. | N.A. | ~~M~~(7,14) | 1, 2, 3*, 4*, 5* |
| 21. Reactor Trip Bypass Breaker | N.A. | N.A. | N.A. | ~~M~~(13), ~~R~~(15) | N.A. | 1, 2, 3*, 4*, 5* |

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## 3/4.3.2 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

### LIMITING CONDITION FOR OPERATION

3.3.2 The Engineered Safety Feature Actuation System (ESFAS) instrumentation channels and interlocks shown in Table 3.3-2 shall be OPERABLE with their Trip Setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-3.

APPLICABILITY: As shown in Table 3.3-2.

ACTION:

a. With an ESFAS Instrumentation or Interlock Trip Setpoint less conservative than the value shown in the Trip Setpoint column but more conservative than the value shown in the Allowable Value column of Table 3.3-3, adjust the Setpoint consistent with the Trip Setpoint value within permissible calibration tolerance.

b. With an ESFAS Instrumentation or Interlock Trip Setpoint less conservative than the value shown in the Allowable Value column of Table 3.3-3, either:

   1. Adjust the Setpoint consistent with the Trip Setpoint value of Table 3.3-3 and determine within 12 hours that the affected channel is OPERABLE; or

   2. Declare the channel inoperable and apply the applicable ACTION statement requirements of Table 3.3-2 until the channel is restored to OPERABLE status with its setpoint adjusted consistent with the Trip Setpoint value.

c. With an ESFAS instrumentation channel or interlock inoperable, take the ACTION shown in Table 3.3-2.

### SURVEILLANCE REQUIREMENTS

4.3.2.1 Each ESFAS instrumentation channel and interlock and the automatic actuation logic and relays shall be demonstrated OPERABLE by performance of the ESFAS Instrumentation Surveillance Requirements specified in Table 4.3-2.

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

| CHANNEL FUNCTIONAL UNIT | CHANNEL CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | TRIP ACTUATING DEVICE OPERATIONAL TEST | ACTUATION LOGIC TEST # | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|---|---|
| 1. Safety Injection | | | | | | |
| a. Manual Initiation | N.A. | N.A. | N.A. | ~~R~~ | N.A. | 1, 2, 3 |
| b. Automatic Actuation Logic and Actuation Relays | N.A. | N.A. | N.A. | N.A. | ~~M~~(1) | 1, 2, 3(3) |
| c. Containment Pressure--High | N.A. | ~~R~~ | N.A. | N.A. | ~~M~~(1) | 1, 2, 3 |
| d. Pressurizer Pressure--Low | ~~S~~ | ~~R~~ | ~~Q~~(5) | N.A. | N.A. | 1, 2, 3(3) |
| e. High Differential Pressure Between the Steam Line Header and any Steam Line | ~~S~~ | ~~R~~ | ~~Q~~(5) | N.A. | N.A. | 1, 2, 3(3) |
| f. Steam Line Flow--High Coincident with: | ~~S~~ | ~~R~~(a)(b) | ~~Q~~(5)(a)(b) | N.A | N.A | 1, 2, 3(3) |
| Steam Generator Pressure--Low | ~~S~~ | ~~R~~(a)(b) | ~~Q~~(5)(a)(b) | N.A. | N.A. | 1, 2, 3(3) |
| or | | | | | | |
| Tavg--Low | ~~S~~ | ~~R~~ | ~~Q~~(5) | N.A. | N.A. | 1, 2, 3(3) |

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

| CHANNEL FUNCTIONAL UNIT | CHANNEL CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | TRIP ACTUATING DEVICE OPERATIONAL TEST | ACTUATION LOGIC TEST # | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|---|---|
| 2. Containment Spray | | | | | | |
| a. Automatic Actuation Logic and Actuation Relays | N.A. | N.A. | N.A. | N.A. | ~~M~~(1) | 1, 2, 3, 4 |
| b. Containment Pressure--High-High | N.A. | ~~R~~ | N.A. | ~~R~~ | ~~M~~(1) | 1, 2, 3 |
| Coincident with: Containment Pressure--High | N.A. | ~~R~~ | N.A. | ~~R~~ | ~~M~~(1) | 1, 2, 3 |
| 3. Containment Isolation | | | | | | |
| a. Phase "A" Isolation | | | | | | |
| 1) Manual Initiation | N.A. | N.A. | N.A. | ~~R~~ | N.A. | 1, 2, 3, 4 |
| 2) Automatic Actuation Logic and Actuation Relays | N.A. | N.A. | N.A. | N.A. | ~~M~~(1) | 1, 2, 3, 4 |
| 3) Safety Injection | See Item 1. above for all Safety Injection Surveillance Requirements. | | | | | |
| b. Phase "B" Isolation | | | | | | |
| 1) Manual Initiation | N.A. | N.A. | N.A. | ~~R~~ | N.A. | 1, 2, 3, 4 |
| 2) Automatic Actuation Logic and Actuation Relays | N.A. | N.A. | N.A. | N.A. | ~~M~~(1) | 1, 2, 3, 4 |

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

| CHANNEL FUNCTIONAL UNIT | CHANNEL CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | TRIP ACTUATING DEVICE OPERATIONAL TEST | ACTUATION LOGIC TEST # | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|---|---|
| 3. Containment Isolation (Continued) | | | | | | |
| 3) Containment Pressure--High-High Coincident with: Containment | N.A. | ~~R~~ | N.A. | ~~R~~ | ~~M~~(1) | 1, 2, 3 |
| Pressure--High | N.A. | ~~R~~ | N.A. | ~~R~~ | ~~M~~(1) | 1, 2, 3 |
| c. Containment Ventilation Isolation | | | | | | |
| 1) Containment Isolation Manual Phase A or Manual Phase B | N.A. | N.A. | N.A. | ~~R~~ | N.A. | 1, 2, 3, 4 |
| 2) Automatic Actuation Logic and Actuation Relays | N.A. | N.A. | N.A. | N.A. | N.A. | |
| 3) Safety Injection | See Item 1. above for all Safety Injection Surveillance Requirements. | | | | | |
| 4) Containment Radioactivity--High | ~~S~~ | ~~R~~ | ~~M~~ | N.A. | N.A. | 1, 2, 3, 4 |
| 4. Steam Line Isolation | | | | | | |
| a. Manual Initiation | N.A. | N.A. | N.A. | ~~R~~ | N.A. | 1, 2, 3 |
| b. Automatic Actuation Logic and Actuation Relays | N.A. | N.A. | N.A. | N.A. | ~~M~~(1) | 1, 2, 3(3) |

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

| CHANNEL FUNCTIONAL UNIT | CHANNEL CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | TRIP ACTUATING DEVICE OPERATIONAL TEST | ACTUATION LOGIC TEST # | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|---|---|
| 4. Steamline Isolation (Continued) | | | | | | |
| c. Containment Pressure--High-High | N.A. | ~~R~~ | N.A. | ~~R~~ | ~~M~~(1) | 1, 2, 3 |
| Coincident with: Containment Pressure--High | N.A. | ~~R~~ | N.A | ~~R~~ | ~~M~~(1) | 1, 2, 3 |
| d. Steam Line Flow--High | ~~S~~(3) | ~~R~~(a)(b) | ~~Q~~(5)(a)(b) | N.A. | N.A. | 1, 2, 3 |
| Coincident with: Steam Generator Pressure--Low | ~~S~~(3) | ~~R~~(a)(b) | ~~Q~~(5)(a)(b) | N.A. | N.A. | 1, 2, 3 |
| or Tavg--Low | ~~S~~(3) | ~~R~~ | ~~Q~~(5) | N.A. | N.A. | 1, 2, 3 |
| 5. Feedwater Isolation | | | | | | |
| a. Automatic Actuation Logic and Actuation Relays | N.A. | N.A. | N.A. | N.A. | ~~R~~ | 1, 2, 3 |
| b. Safety Injection | See Item 1. above for all Safety Injection Surveillance Requirements. | | | | | |
| c. Steam Generator Water Level--High-High | ~~S~~ | ~~R~~(a)(b) | ~~Q~~(a)(b) | N.A. | N.A. | 1, 2, 3 |
| 6. Auxiliary Feedwater (2) | | | | | | |
| a. Automatic Actuation Logic and Actuation Relays | N.A. | N.A. | N.A. | N.A. | ~~R~~ | 1, 2, 3 |
| b. Steam Generator Water Level--Low-Low | ~~S~~ | ~~R~~(a)(b) | ~~Q~~(a)(b) | N.A. | N.A. | 1, 2, 3 |

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

| CHANNEL FUNCTIONAL UNIT | CHANNEL CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | TRIP ACTUATING DEVICE OPERATIONAL TEST | ACTUATION LOGIC TEST # | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|---|---|
| 6. Auxiliary Feedwater (Continued) | | | | | | |
| c. Safety Injection | See Item 1. above for all Safety Injection Surveillance Requirements. | | | | | |
| d. Bus Stripping | N.A. | ~~R~~ | N.A. | ~~R~~ | N.A. | 1, 2, 3 |
| e. Trip of All Main Feedwater Pump Breakers. | N.A. | N.A. | N.A. | ~~R~~ | N.A. | 1. 2 |
| 7. Loss of Power | | | | | | |
| a. 4.16 kV busses A and B (Loss of Voltage) | N.A. | ~~R~~ | N.A. | ~~R~~ | N.A. | 1, 2, 3, 4 |
| b. 480V Load Centers 3A, 3B, 3C, 3D and 4A, 4B, 4C, 4D Undervoltage | ~~S~~ | ~~R~~ | N.A. | ~~M~~(1) | N.A. | 1, 2, 3, 4 |
| Coincident with: Safety Injection | See Item 1. above for all Safety Injection Surveillance Requirements. | | | | | |
| c. 480V Load Centers 3A, 3B, 3C, 3D and 4A, 4B, 4C, 4D Degraded Voltage | ~~S~~ | ~~R~~ | N.A. | ~~M~~(1) | N.A. | 1, 2, 3, 4 |

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.3-2 (Continued)
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

| CHANNEL FUNCTIONAL UNIT | CHANNEL CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | TRIP ACTUATING DEVICE OPERATIONAL TEST | ACTUATION LOGIC TEST # | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|---|---|
| 8. Engineering Safety Features Actuation System Interlocks | | | | | | |
| a. Pressurizer Pressure | N.A. | ~~R~~ | ~~Q~~(5) | N.A. | N.A. | 1, 2, 3(3) |
| b. Tavg--Low | N.A. | ~~R~~ | ~~Q~~(5) | N.A. | N.A. | 1, 2, 3(3) |
| 9. Control Room Ventilation Isolation | | | | | | |
| a. Automatic Actuation Logic and Actuation Relays | N.A. | N.A. | N.A. | N.A. | N.A. | |
| b. Safety Injection | See Item 1. above for all Safety Injection Surveillance Requirements. | | | | | |
| c. Containment Radioactivity--High | ~~S~~ | ~~R~~ | ~~M~~ | N.A. | N.A. | (4) |
| d. Containment Isolation Manual Phase A or Manual Phase B | N.A. | N.A. | N.A. | ~~R~~ | N.A. | 1, 2, 3, 4 |
| e. Control Room Air Intake Radiation Level | ~~S~~ | ~~R~~ | ~~M~~ | N.A. | N.A. | All |

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## 3/4.3.3 MONITORING INSTRUMENTATION

### RADIATION MONITORING FOR PLANT OPERATIONS

### LIMITING CONDITION FOR OPERATION

3.3.3.1 The radiation monitoring instrumentation channels for plant operations shown in Table 3.3-4 shall be OPERABLE with their Alarm/Trip Setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3-4.

ACTION:

a. With a radiation monitoring channel Alarm/Trip Setpoint for plant operations exceeding the value shown in Table 3.3-4, adjust the Setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels for plant operations inoperable, take the ACTION shown in Table 3.3-4.

c. The provisions of Specification 3.0.3 are not applicable.

### SURVEILLANCE REQUIREMENTS

4.3.3.1 Each radiation monitoring instrumentation channel for plant operations shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and ANALOG CHANNEL OPERATIONAL TEST for the MODES and at the frequencies shown in Table 4.3-3.

except

TABLE 3.3-4 (Continued)

ACTION STATEMENTS (Continued)

ACTION 27 - In MODES 5 or 6 (~~expect~~ during CORE ALTERATION or movement of irradiated fuel within the containment): With the number of OPERABLE Channels less than the Minimum Channels OPERABLE requirement perform the following:

1) Obtain and analyze appropriate grab samples at least once per 24 hours, and

2) Monitor containment atmosphere with area radiation monitors.

Otherwise, isolate all penetrations that provide direct access from the containment atmosphere to the outside atmosphere.

During CORE ALTERATION or movement of irradiated fuel within the containment: With the number of OPERABLE Channels less than the Minimum Channels OPERABLE requirements, comply with ACTION statement requirements of Specification 3.9.9 and 3.9.13.

ACTION 28 - With the number of OPERABLE channels less than the Minimum Channels OPERABLE requirement, immediately suspend operations in the Spent Fuel Pool area involving spent fuel manipulations.

Replace each marked through Surveillance Frequency with "SFCP".

## TABLE 4.3-3

## RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS SURVEILLANCE REQUIREMENTS

| FUNCTIONAL UNIT | CHANNEL CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|
| 1. Containment | | | | |
| a. Containment Atmosphere Radioactivity--High | ~~S~~ | ~~R~~ | ~~Q~~ | All |
| b. RCS Leakage Detection | | | | |
| 1) Particulate Radio-activity | ~~S~~ | ~~R~~ | ~~Q~~ | 1, 2, 3, 4 |
| 2) Gaseous Radioactivity | ~~S~~ | ~~R~~ | ~~Q~~ | 1, 2, 3, 4 |
| 2. Spent Fuel Pool Areas | | | | |
| a. Unit 3 Radioactivity--High Gaseous | ~~S~~ | ~~R~~ | ~~Q~~ | * |
| b. Unit 4 (Plant Vent) Radioactivity--High Gaseous# (SPING and PRMS) | ~~S~~ | ~~R~~ | ~~Q~~ | * |

### TABLE NOTATIONS

* With irradiated fuel in the fuel storage pool areas.

\# Unit 4 Spent Fuel Pool Area is monitored by Plant Vent radioactivity instrumentation.

MOVABLE INCORE DETECTORS

LIMITING CONDITION FOR OPERATION

3.3.3.2 The Movable Incore Detection System shall be OPERABLE with:

a. At least 16 detector thimbles when used for recalibration and check of the Excore Neutron Flux Detection System and monitoring the QUANDRANT POWER TILT RATIO*, and at least 38 detector thimbles when used for monitoring $F^N_{\Delta H}$, $F_Q(Z)$ and $F_{xy}(Z)$.

b. A minimum of two detector thimbles per core quadrant, and

c. Sufficient movable detectors, drive, and readout equipment to map these thimbles.

APPLICABLITY: When the Movable Incore Detection System is used for:

a. Recalibration of the Excore Neutron Flux Detection System, or

b. Monitoring the QUADRANT POWER TILT RATIO*, or

c. Measurement of $F^N_{\Delta H}$, $F_Q(Z)$ and $F_{xy}(Z)$.

ACTION:

With the Movable Incore Detection System inoperable, do not use the system for the above applicable monitoring or calibration functions. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.2 The Movable Incore Detection System shall be demonstrated OPERABLE ~~at least once per 24 hours~~ Insert 1 by normalizing each detector output when required for:

a. Recalibration of the Excore Neutron Flux Detection System, or

b. Monitoring the QUADRANT POWER TILT RATIO*, or

c. Measurement of $F^N_{\Delta H}$, $F_Q(Z)$ and $F_{xy}(Z)$.

* Exception to the 16 detector thimble requirement of monitoring the QUADRANT POWER TILT RATIO is acceptable when performing Specification 4.2.4.2 using two sets of four symmetric thimbles.

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## ACCIDENT MONITORING INSTRUMENTATION

### LIMITING CONDITION FOR OPERATION

3.3.3.3 The accident monitoring instrumentation channels shown in Table 3.3-5 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3-5.

ACTION:

a. As shown in Table 3.3-5.

b. The provisions of Specification 3.0.4 are not applicable to ACTIONS in Table 3.3-5 that require a shutdown.

c. Separate Action entry is allowed for each Instrument.

### SURVEILLANCE REQUIREMENTS

4.3.3.3 Each accident monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION at the frequencies shown in Table 4.3-4.

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.3-4

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

| INSTRUMENT | | CHANNEL CHECK | CHANNEL CALIBRATION |
|---|---|---|---|
| 1. | Containment Pressure (Wide Range) | ~~M~~ | ~~R~~ |
| 2. | Containment Pressure (Narrow Range) | ~~M~~ | ~~R~~ |
| 3. | Reactor Coolant Outlet Temperature - $T_{HOT}$ (Wide Range) | ~~M~~ | ~~R~~ |
| 4. | Reactor Coolant Inlet Temperature - $T_{COLD}$ (Wide Range) | ~~M~~ | ~~R~~ |
| 5. | Reactor Coolant Pressure - Wide Range | ~~M~~ | ~~R~~ |
| 6. | Pressurizer Water Level | ~~M~~ | ~~R~~ |
| 7. | Auxiliary Feedwater Flow Rate | ~~M~~ | ~~R~~ |
| 8. | Reactor Coolant System Subcooling Margin Monitor | ~~M~~ | ~~R~~ |
| 9. | PORV Position Indicator (Primary Detector) | ~~M~~ | ~~R~~ |
| 10. | PORV Block Valve Position Indicator | ~~M~~ | ~~R~~ |
| 11. | Safety Valve Position Indicator (Primary Detector) | ~~M~~ | ~~R~~ |
| 12. | Containment Water Level (Narrow Range) | ~~M~~ | ~~R~~ |
| 13. | Containment Water Level (Wide Range) | ~~M~~ | ~~R~~ |
| 14. | In Core Thermocouples (Core Exit Thermocouples) | ~~M~~ | ~~R~~ |
| 15. | Containment - High Range Area Radiation Monitor | ~~M~~ | ~~R~~* |
| 16. | Reactor Vessel Level Monitoring System | ~~M~~ | ~~R~~ |
| 17. | Neutron Flux, Backup NIS (Wide Range) | ~~M~~ | ~~R~~ |
| 18. | DELETED | | |
| 19. | High Range - Noble Gas Effluent Monitors | | |
| | a. Plant Vent Exhaust | ~~M~~ | ~~R~~ |
| | b. Unit 3 - Spent Fuel Pit Exhaust | ~~M~~ | ~~R~~ |
| | c. Condenser Air Ejectors | ~~M~~ | ~~R~~ |
| 20. | RWST Water Level | ~~M~~ | ~~R~~ |
| 21. | Steam Generator Water Level (Narrow Range) | ~~M~~ | ~~R~~ |
| 22. | Containment Isolation Valve Position Indication | ~~M~~ | ~~R~~ |

*Acceptable criteria for calibration are provided in Table II.F.1-3 of NUREG-0737.

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## EXPLOSIVE GAS MONITORING INSTRUMENTATION

### LIMITING CONDITION FOR OPERATION

3.3.3.6 The explosive gas monitoring instrumentation channels shown in Table 3.3-8 shall be OPERABLE with their Alarm/Trip Setpoints set to ensure that the limits of Specification 3.7.8 are not exceeded.

APPLICABILITY: As shown in Table 3.3-8

ACTION:

a. With an explosive gas monitoring instrumentation channel Alarm/Trip Setpoint less conservative than required by the above specification, declare the channel inoperable or change the setpoint so it is acceptably conservative.

b. With less than the minimum number of explosive gas monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3-8. Restore the inoperable instrumentation to OPERABLE status within 30 days and, if unsuccessful prepare and submit a special report to the Commission within 30 days to explain why this inoperability was not corrected in a timely manner.

c. The provisions of Specification 3.0.3 are not applicable.

### SURVEILLANCE REQUIREMENTS

4.3.3.6 Each explosive gas monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, CHANNEL CALIBRATION and ANALOG CHANNEL OPERATIONAL TEST at the frequencies shown in Table 4.3-6.

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.3-6

EXPLOSIVE GAS MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

| INSTRUMENT | CHANNEL CHECK | SOURCE CHECK | CHANNEL CALIBRATION | ANALOG CHANNEL OPERATIONAL TEST | MODES FOR WHICH SURVEILLANCE IS REQUIRED |
|---|---|---|---|---|---|
| 1. GAS DECAY TANK SYSTEM (Explosive Gas Monitoring System) | | | | | |
| a. Hydrogen and Oxygen Monitors | ~~D~~ | N.A. | ~~Q~~(1,2) | ~~M~~ | * |

TABLE NOTATION

* During GAS DECAY TANK SYSTEM operation.

(1) The CHANNEL CALIBRATION shall include the use of standard gas samples containing a nominal.

a. One volume percent hydrogen, balance nitrogen, and

b. Four volume percent hydrogen, balance nitrogen.

(2) The CHANNEL CALIBRATION shall include the use of standard gas samples containing a nominal:

a. One volume percent oxygen, balance nitrogen, and

b. Four volume percent oxygen, balance nitrogen.

## 3/4.4 REACTOR COOLANT SYSTEM

## 3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

### STARTUP AND POWER OPERATION

### LIMITING CONDITION FOR OPERATION

3.4.1.1 All reactor coolant loops shall be in operation.

APPLICABILITY: MODES 1 and 2.

ACTION:

With less than the above required reactor coolant loops in operation, be in at least HOT STANDBY within 6 hours.

### SURVEILLANCE REQUIREMENTS

4.4.1.1 The above required reactor coolant loops shall be verified in operation and circulating reactor coolant ~~at least once per 12 hours~~.

Insert 1

REACTOR COOLANT SYSTEM

HOT STANDBY

LIMITING CONDITION FOR OPERATION

3.4.1.2 All of the reactor coolant loops listed below shall be OPERABLE with all reactor coolant loops in operation when the Reactor Trip breakers are closed and two reactor coolant loops listed below shall be OPERABLE with at least one reactor coolant loop in operation when the Reactor Trip breakers are open:*

a. Reactor Coolant Loop A and its associated steam generator and reactor coolant pump,

b. Reactor Coolant Loop B and its associated steam generator and reactor coolant pump, and

c. Reactor Coolant Loop C and its associated steam generator and reactor coolant pump.

APPLICABILITY: MODE 3

ACTION:

a. With less than the above required reactor coolant loops OPERABLE, restore the required loops to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. With less than three reactor coolant loop in operation and the Reactor Trip breakers in the closed position, within 1 hour open the Reactor Trip breakers.

c. With no reactor coolant loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required reactor coolant loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.2.1 At least the above required reactor coolant pumps, if not in operation, shall be determined OPERABLE ~~once per 7 days~~ by verifying correct breaker alignments and indicated power availability.

4.4.1.2.2 The required steam generators shall be determined OPERABLE by verifying secondary side water level to be greater than or equal to 10% ~~at least once per 12 hours~~.

4.4.1.2.3 The required reactor coolant loops shall be verified in operation and circulating reactor coolant ~~at least once per 12 hours.~~

Insert 1

* All reactor coolant pumps may be deenergized for up to 1 hour provided: (1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

SURVEILLANCE REQUIREMENTS

4.4.1.3.1 The required reactor coolant pump(s), if not in operation, shall be determined OPERABLE ~~once per 7 days~~ by verifying correct breaker alignments and indicated power availability.

4.4.1.3.2 The required steam generator(s) shall be determined OPERABLE by verifying secondary side water level to be greater than or equal to 10% ~~at least once per 12 hours~~.

4.4.1.3.3 At least one reactor coolant or RHR loop shall be verified in operation and circulating reactor coolant ~~at least once per 12 hours~~.

Insert 1

REACTOR COOLANT SYSTEM

COLD SHUTDOWN - LOOPS FILLED

LIMITING CONDITION FOR OPERATION

3.4.1.4.1 At least one residual heat removal (RHR) loop shall be OPERABLE and in operation*, and either:

a. One additional RHR loop shall be OPERABLE**, or

b. The secondary side water level of at least two steam generators shall be greater than 10%.

APPLICABILITY: MODE 5 with reactor coolant loops filled***.

ACTION:

a. With one of the RHR loops inoperable or with less than the required steam generator water level, immediately initiate corrective action to return the inoperable RHR loop to OPERABLE status or restore the required steam generator water level as soon as possible.

b. With no RHR loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required RHR loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.4.1.1 The secondary side water level of at least two steam generators when required shall be determined to be within limits ~~at least once per 12 hours~~.

4.4.1.4.1.2 At least one RHR loop shall be determined to be in operation and circulating reactor coolant ~~at least once per 12 hours~~.

Insert 1

* The RHR pump may be deenergized for up to 1 hour provided: (1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

** One RHR loop may be inoperable for up to 2 hours for surveillance testing provided the other RHR loop is OPERABLE.

*** A reactor coolant pump shall not be started with one or more of the Reactor Coolant System cold leg temperatures less than or equal to 275°F unless the secondary water temperature of each steam generator is less than 50°F above each of the Reactor Coolant System cold leg temperatures.

REACTOR COOLANT SYSTEM

COLD SHUTDOWN - LOOPS NOT FILLED

LIMITING CONDITION FOR OPERATION

3.4.1.4.2 Two residual heat removal (RHR) loops shall be OPERABLE* and at least one RHR loop shall be in operation.**

APPLICABILITY: MODE 5 with reactor coolant loops not filled.

ACTION:

a. With less than the above required RHR loops OPERABLE, immediately initiate corrective action to return the required RHR loops to OPERABLE status as soon as possible.

b. With no RHR loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required RHR loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.4.2 At least one RHR loop shall be determined to be in operation and circulating reactor coolant ~~at least once per 12 hours~~.

Insert 1

---

* One RHR loop may be inoperable for up to 2 hours for surveillance testing provided the other RHR loop is OPERABLE.

** The RHR pump may be deenergized for up to 1 hour provided: (1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

REACTOR COOLANT SYSTEM

3/4.4.3 PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.3 The pressurizer shall be OPERABLE with a water volume of less than or equal to 92% of indicated level, and at least two groups of pressurizer heaters each having a capacity of at least 125 kW and capable of being supplied by emergency power.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With only one group of pressurizer heaters OPERABLE, restore at least two groups to OPERABLE status within 72 hours** or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With the pressurizer otherwise inoperable, be in at least HOT STANDBY with the Reactor Trip System breakers open within 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.3.1 The pressurizer water volume shall be determined to be within its limit ~~at least once per 12 hours~~.

4.4.3.2 The capacity of each of the above required groups of pressurizer heaters shall be verified to be at least 125 kw ~~at least once per 18 months~~.

Insert 1

** 14 days if the inoperability is associated with an inoperable diesel generator.

Insert 1

REACTOR COOLANT SYSTEM

RELIEF VALVES

SURVEILLANCE REQUIREMENTS

4.4.4 Each block valve shall be demonstrated OPERABLE ~~at least once per 92 days~~ by operating the valve through one complete cycle of full travel unless the block valve is closed with power removed in order to meet the requirements of Specification 3.4.4 or is closed to provide an isolation function.

REACTOR COOLANT SYSTEM

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

## LIMITING CONDITION FOR OPERATION

3.4.6.1 The following Reactor Coolant System Leakage Detection Systems shall be OPERABLE:

a. The Containment Atmosphere Gaseous or Particulate Radioactivity Monitoring System, and

b. A Containment Sump Level Monitoring System.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With both the Particulate and Gaseous Radioactivity Monitoring Systems inoperable, operation may continue for up to 7 days provided:

1) A Containment Sump Level Monitoring System is OPERABLE;

2) Appropriate grab samples are obtained and analyzed at least once per 24 hours;

3) A Reactor Coolant System water inventory balance is performed at least once per 8* hours except when operating in shutdown cooling mode; and

4) Containment Purge, Exhaust and Instrument Air Bleed valves are maintained closed.**

Otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With no Containment Sump Level Monitoring System operable, restore at least one Containment Sump Level Monitoring System to OPERABLE status within 7 days, or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

## SURVEILLANCE REQUIREMENTS

4.4.6.1 The Leakage Detection System shall be demonstrated OPERABLE by:

a. Containment Atmosphere Gaseous and Particulate Monitoring System-performance of CHANNEL CHECK, CHANNEL CALIBRATION and ANALOG CHANNEL OPERATIONAL TEST at the frequencies specified in Table 4.3-3, and

b. Containment Sump Level Monitoring System-performance of CHANNEL CALIBRATION ~~at least once per 18 months~~.

Insert 1

---

* Not required to be performed until 12 hours after establishment of steady state operation.

** Instrument Air Bleed valves may be opened intermittently under administrative controls.

2. The leakage* from the remaining isolating valves in each high pressure line having a valve not meeting the criteria of Table 3.4-1, as listed in Table 3.4-1, shall be determined and recorded daily. The positions of the other valves located in the high pressure line having the leaking valve shall be recorded daily unless they are manual valves located inside containment.

Otherwise be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With any Reactor Coolant System Pressure Isolation Valve leakage greater than 5 gpm, reduce leakage to below 5 gpm within 1 hour, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2.1 Reactor Coolant System operational leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the containment atmosphere gaseous or particulate radioactivity monitor ~~at least once per 12 hours~~.

Insert 1

b. Monitoring the containment sump level ~~at least once per 12 hours.~~

c.** Performance of a Reactor Coolant System water inventory balance ~~at least once per 72*** hours~~; and

d. Monitoring the Reactor Head Flange Leakoff System ~~at least once per 24 hours~~; and

e. Verifying primary-to-secondary leakage is ≤ 150 gallons per day through any one SG ~~at least once per 72*** hours~~.

4.4.6.2.2 Each Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1 shall be demonstrated OPERABLE by verifying leakage* to be within its limit:

Insert 1

a. ~~At least once per 18 months~~.

b. Prior to entering MODE 2 whenever the plant has been in COLD SHUTDOWN for 7 days or more and if leakage testing has not been performed in the previous 9 months, and

c. Prior to returning the valve to service following maintenance, repair or replacement work on the valve.

* To satisfy ALARA requirements, leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating valve compliance with the leakage criteria.

** Not applicable to primary-to-secondary leakage.

*** Not required to be performed until 12 hours after establishment of steady state operation.

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## 3/4.4.7 CHEMISTRY

### LIMITING CONDITION FOR OPERATION

3.4.7 The Reactor Coolant System chemistry shall be maintained within the limits specified in Table 3.4-2.

APPLICABILITY: At all times.

ACTION:

MODES 1, 2, 3 and 4:

a. With any one or more chemistry parameter in excess of its Steady-State Limit but within its Transient Limit, restore the parameter to within its Steady-State Limit within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; and

b. With any one or more chemistry parameter in excess of its Transient Limit, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

At All Other Times:

With the concentration of either chloride or fluoride in the Reactor Coolant System in excess of its Steady-State Limit for more than 24 hours or in excess of its Transient Limit, reduce the pressurizer pressure to less than or equal to 500 psig, if applicable, and perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the Reactor Coolant System; determine that the Reactor Coolant System remains acceptable for continued operation prior to increasing the pressurizer pressure above 500 psig or prior to proceeding to MODE 4.

### SURVEILLANCE REQUIREMENTS

4.4.7 The Reactor Coolant System chemistry shall be determined to be within the limits by analysis of those parameters at the frequencies specified in Table 4.4-3.

Replace each marked through Surveillance Frequency with "SFCP".

TABLE 4.4-3

REACTOR COOLANT SYSTEM

CHEMISTRY LIMITS SURVEILLANCE REQUIREMENTS

| PARAMETER | SAMPLE AND ANALYSIS FREQUENCY |
|---|---|
| Dissolved Oxygen* | ~~At least 5 times per week not to exceed 72 hours between samples~~ |
| Chloride** | ~~At least 5 times per week not to exceed 72 hours between samples~~ |
| Fluoride** | ~~At least 5 times per week not to exceed 72 hours between samples~~ |

* Not required with average reactor coolant temperature less than or equal to 250°F.

** Not required when reactor is defueled and RCS forced circulation is unavailable.

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## 3/4.4.8 SPECIFIC ACTIVITY

### LIMITING CONDITION FOR OPERATION

3.4.8 The specific activity of the primary coolant shall be limited to:

a. Less than or equal to 0.25 microcuries per gram DOSE EQUIVALENT I-131, and

b. Less than or equal to 447.7 microcuries per gram DOSE EQUIVALENT XE-133.

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

ACTION:

a. With the specific activity of the reactor coolant greater than 0.25 microcuries per gram DOSE EQUIVALENT I-131, verify DOSE EQUIVALENT I-131 is less than or equal to 60 microcuries per gram once per 4 hours.

b. With the specific activity of the reactor coolant greater than 0.25 microcuries per gram DOSE EQUIVALENT I-131, but less than or equal to 60 microcuries per gram, operation may continue for up to 48 hours while efforts are made to restore DOSE EQUIVALENT I-131 to within the 0.25 microcuries per gram limit. Specification 3.0.4 is not applicable.

c. With the specific activity of the reactor coolant greater than 0.25 microcuries per gram DOSE EQUIVALENT I-131 for greater than or equal to 48 hours during one continuous time interval, or greater than 60 microcuries per gram DOSE EQUIVALENT I-131, be in HOT STANDBY within 6 hours and COLD SHUTDOWN within the next 30 hours.

d. With the specific activity of the reactor coolant greater than 447.7 microcuries per gram DOSE EQUIVALENT XE-133, operation may continue for up to 48 hours while efforts are made to restore DOSE EQUIVALENT XE-133 to within the 447.7 microcuries per gram limit. Specification 3.0.4 is not applicable.

e. With the specific activity of the reactor coolant greater than 447.7 microcuries per gram DOSE EQUIVALENT XE-133 for greater than or equal to 48 hours during one continuous time interval, be in HOT STANDBY within 6 hours and COLD SHUTDOWN within the next 30 hours.

### SURVEILLANCE REQUIREMENTS

4.4.8 The specific activity of the reactor coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-4.

## TABLE 4.4-4

## REACTOR COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

| TYPE OF MEASUREMENT AND ANALYSIS | SAMPLE AND ANALYSIS FREQUENCY | MODES IN WHICH SAMPLE AND ANALYSIS REQUIRED |
|---|---|---|
| 1. NOT USED | | |
| 2. Tritium Activity Determination | ~~1 per 7 days.~~ | 1, 2, 3, 4 |
| 3. Isotopic Analysis for DOSE EQUIVALENT I-131 | a) ~~1 per 14 days.~~<br>b) One sample between 2 and 6 hours following a THERMAL POWER change exceeding 15% of the RATED THERMAL POWER within a 1 hour period. | 1, 2, 3, 4 |
| 4. Radiochemical Isotopic Determination Including Gaseous Activity | ~~Monthly~~ | 1, 2, 3, 4 |
| 5. Isotopic Analysis for DOSE EQUIVALENT XE-133 | ~~1 per 7 days~~ | 1, 2, 3, 4 |
| 6. NOT USED | | |

Insert 1

REACTOR COOLANT SYSTEM

OVERPRESSURE MITIGATING SYSTEMS

SURVEILLANCE REQUIREMENTS

4.4.9.3.1 Each PORV shall be demonstrated OPERABLE by:

a. Performance of an ANALOG CHANNEL OPERATIONAL TEST* on the PORV actuation channel, but excluding valve operation, within 31 days prior to entering a condition in which the PORV is required OPERABLE and at least once per 31 days thereafter when the PORV is required OPERABLE.

b. Performance of a CHANNEL CALIBRATION on the PORV actuation channel ~~at least once per 18 months;~~ and

Insert 1

c. Verifying the PORV block valve is open ~~at least once per 72 hours~~ when the PORV is being used for overpressure protection.

d. While the PORVs are required to be OPERABLE, the backup nitrogen supply shall be verified OPERABLE ~~at least once per 24 hours~~.*

4.4.9.3.2 The 2.20 square inch vent shall be verified to be open ~~at least once per 12 hours~~** when the vent(s) is being used for overpressure protection.

4.4.9.3.3 Verify the high pressure injection flow path to the RCS is isolated ~~at least once per 24 hours~~ by closed valves with power removed or by locked closed manual valves.

Insert 1

* Not required to be met until 12 hours after decreasing RCS cold leg temperature to ≤ 275°F.

** Except when the vent pathway is provided with a valve which is locked, sealed, or otherwise secured in the open position, then verify these valves open at least once per 31 days.

REACTOR COOLANT SYSTEM

3/4.4.11 REACTOR COOLANT SYSTEM VENTS

LIMITING CONDITION FOR OPERATION

3.4.11 At least one Reactor Coolant System vent path consisting of at least two vent valves in series and powered from emergency busses shall be OPERABLE and closed at each of the following locations:

a. Reactor vessel head, and

b. Pressurizer steam space

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

ACTION:

a. With one of the above Reactor Coolant System vent paths inoperable, STARTUP and/or POWER OPERATION may continue provided the inoperable vent path is maintained closed with power removed from the valve actuator of all the vent valves in the inoperable vent path; restore the inoperable vent path to OPERABLE status within 30 days, or, be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With both Reactor Coolant System vent paths inoperable; maintain the inoperable vent path closed with power removed from the valve actuators of all the vent valves in the inoperable vent paths, and restore at least one of the vent paths to OPERABLE status within 72 hours or be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

Insert 1

SURVEILLANCE REQUIREMENTS

4.4.11 Each Reactor Coolant System vent path shall be demonstrated OPERABLE ~~at least once per 18 months~~ by:

a. Verifying all manual isolation valves in each vent path are locked in the open position,

b. Cycling each vent valve through at least one complete cycle of full travel from the control room, and

c. Verifying flow through the Reactor Coolant System vent paths during venting.

## 3/4.5 EMERGENCY CORE COOLING SYSTEMS

### 3/4.5.1 ACCUMULATORS

#### LIMITING CONDITION FOR OPERATION

3.5.1 Each Reactor Coolant System (RCS) accumulator shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3*.

ACTION:

a. With one accumulator inoperable, except as a result of boron concentration not being within limits, restore the inoperable accumulator to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and reduce pressurizer pressure to less than 1000 psig within the following 6 hours.

b. With one accumulator inoperable due to the boron concentration not being within the limits, restore boron concentration back to the required limits within 72 hours, or be in at least HOT STANDBY within 6 hours and reduce pressurizer pressure to less than 1000 psig within the following 6 hours.

#### SURVEILLANCE REQUIREMENTS

4.5.1.1 Each accumulator shall be demonstrated OPERABLE: Insert 1

a. ~~At least once per 12 hours~~ by:

1) Verifying the borated water volume in each accumulator is between 6520 and 6820 gallons, and

2) Verifying that the nitrogen cover pressure in each accumulator is between 600 and 675 psig, and

3) Verifying that each accumulator isolation valve is open by control room indication (power may be restored to the valve operator to perform this surveillance if redundant indicator is inoperable).

*Pressurizer pressure above 1000 psig.

SURVEILLANCE REQUIREMENTS (Continued)

Insert 1

b. ~~At least once per 31 days~~ and within 6 hours after each solution volume increase of greater than or equal to 1% of tank volume by verifying the boron concentration of the solution in the water-filled accumulator is between 2300 and 2600 ppm; *

c. ~~At least once per 31 days~~, when the RCS pressure is above 1000 psig, by verifying that the power to the isolation valve operator is disconnected by a locked open breaker.

d. ~~At least once per 18 months~~, each accumulator check valve shall be checked for operability.

## SURVEILLANCE REQUIREMENTS

4.5.2 Each ECCS component and flow path shall be demonstrated OPERABLE:

a. ~~At least once per 12 hours~~ by verifying by control room indication that the following valves are in the indicated positions with power to the valve operators removed:

| Valve Number | Valve Function | Valve Position |
|---|---|---|
| 864A and B | Supply from RWST to ECCS | Open |
| 862A and B | RWST Supply to RHR pumps | Open |
| 863A and B | RHR Recirculation | Closed |
| 866A and B | H.H.S.I. to Hot Legs | Closed |
| HCV-758* | RHR HX Outlet | Open |

To permit temporary operation of these valves for surveillance or maintenance purposes, power may be restored to these valves for a period not to exceed 24 hours.

b. ~~At least once per 31 days~~ by:

Insert 1

1) Verifying that the ECCS piping is full of water by venting the ECCS pump casings and accessible discharge piping,

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, and

3) Verifying that each RHR Pump develops the indicated differential pressure applicable to the operating conditions in accordance with Figure 3.5-1 when tested pursuant to Specification 4.0.5.

c. ~~At least once per 92 days~~ by:

1) Verifying that each SI pump develops the indicated differential pressure applicable to the operating conditions when tested pursuant to Specification 4.0.5.

SI pump $\geq$ 1083 psid at a metered flowrate $\geq$ 300 gpm (normal alignment or Unit 4 SI pumps aligned to Unit 3 RWST), or

$\geq$ 1113 psid at a metered flowrate $\geq$ 280 gpm (Unit 3 SI pumps aligned to Unit 4 RWST).

*Air Supply to HCV-758 shall be verified shut off and sealed closed once per 31 days.

d. By a visual inspection which verifies that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restriction of the pump suctions during LOCA conditions. The visual inspection shall be performed:

1) For all accessible areas of the containment prior to establishing CONTAINMENT INTEGRITY, and

2) At least once daily of the areas affected within containment by containment entry and during the final entry when CONTAINMENT INTEGRITY is established.

e. ~~At least once per 18 months~~ by:

Insert 1

1) Verifying automatic isolation and interlock action of the RHR system from the Reactor Coolant System by ensuring that with a simulated or actual Reactor Coolant System pressure signal greater than or equal to 525 psig the interlocks cause the valves to automatically close and prevent the valves from being opened, and

2) Verifying correct interlock action to ensure that the RWST is isolated from the RHR System during RHR System operation and to ensure that the RHR System cannot be pressurized from the Reactor Coolant System unless the above RWST Isolation Valves are closed.

3) A visual inspection of the containment sump and verifying that the suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or abnormal corrosion.

f. At least once per 18 months, during shutdown, by:

1) Verifying that each automatic valve in the flow path actuates to its correct position on Safety Injection actuation test signal, and

2) Verifying that each of the following pumps start automatically upon receipt of a Safety Injection actuation test signal:

a) Safety Injection pump, and

b) RHR pump.

SURVEILLANCE REQUIREMENTS

g. By verifying the correct position of each electrical and/or mechanical position stop for the following ECCS throttle valves:

1) Within 4 hours following completion of each valve stroking operation or maintenance on the valve when the ECCS components are required to be OPERABLE, and

2) ~~At least once per 18 months.~~ Insert 1

RHR System
Valve Number

HCV-*-758
MOV-*-872

EMERGENCY CORE COOLING SYSTEMS

3/4.5.4 REFUELING WATER STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.5.4 For single Unit operation, one refueling water storage tank (RWST) shall be OPERABLE or for dual Unit operation two RWSTs shall be OPERABLE with:

a. A minimum indicated borated water volume of 320,000 gallons per RWST,

b. A boron concentration between 2400 ppm and 2600 ppm,

c. A minimum solution temperature of 39°F, and

d. A maximum solution temperature of 100°F.

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

ACTION:

With less than the required number of RWST(s) OPERABLE, restore the tank(s) to OPERABLE status within 1 hour or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.5.4 The required RWST(s) shall be demonstrated OPERABLE:

a. ~~At least once per 7 days~~ by:

Insert 1

1) Verifying the indicated borated water volume in the tank, and

2) Verifying the boron concentration of the water.

b. By verifying the RWST temperature is within limits whenever the outside air temperature is less than 39°F or greater than 100°F at the following frequencies:

1) Within one hour upon the outside temperature exceeding its limit for consecutive 23 hours, and

2) At least once per 24 hours while the outside temperature exceeds its limit.

## 3/4.6 CONTAINMENT SYSTEMS

### 3/4.6.1 PRIMARY CONTAINMENT

### CONTAINMENT INTEGRITY

#### LIMITING CONDITION FOR OPERATION

3.6.1.1 Primary CONTAINMENT INTEGRITY shall be maintained.*

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

ACTION:

Without primary CONTAINMENT INTEGRITY, restore CONTAINMENT INTEGRITY within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

#### SURVEILLANCE REQUIREMENTS

4.6.1.1 CONTAINMENT INTEGRITY shall be demonstrated:

a. ~~At least once per 31 days~~ by verifying that all penetrations** not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in their closed positions;

b. By verifying that each containment air lock is in compliance with the requirements of Specification 3.6.1.3.

Insert 1

---

* Exception may be taken under Administrative Controls for opening of valves and airlocks necessary to perform surveillance, testing requirements and/or corrective maintenance. In addition, Specification 3.6.4 shall be complied with.

** Except valves, blind flanges, and deactivated automatic valves which are located inside the containment and are locked, sealed or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except that such verification need not be performed more often than once per 92 days.

CONTAINMENT SYSTEMS

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE:

a. Following each closing, at the frequency specified in the Containment Leakage Rate Testing Program, by verifying that the seals have not been damaged and have seated properly by vacuum testing the volume between the door seals in accordance with approved plant procedures.

b. By conducting overall air lock leakage tests in accordance with the Containment Leakage Rate Testing Program.

c. ~~At least once per 24 months~~ by verifying that only one door in each air lock can be opened at a time.

Insert 1

CONTAINMENT SYSTEMS

INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.4 Primary containment internal pressure shall be maintained between -2 and +1 psig.

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

ACTION:

With the containment internal pressure outside of the limits above, restore the internal pressure to within the limits within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.4 The primary containment internal pressure shall be determined to be within the limits ~~at least once per 12 hours~~.

Insert 1

CONTAINMENT SYSTEMS

AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.5 Primary containment average air temperature shall not exceed 125°F and shall not exceed 120°F by more than 336 equivalent hours* during a calendar year.

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

ACTION:

With the containment average air temperature greater than 125°F or greater than 120°F for more than 336 equivalent hours* during a calendar year, reduce the average air temperature to within the applicable limit within 8 hours, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.5 The primary containment average air temperature shall be the arithmetical average of the temperatures at the following locations and shall be determined ~~at least once per 24 hours~~:

Insert 1

Approximate Location

| | | | |
|---|---|---|---|
| a. | 0° Azimuth | 58 feet elevation |
| b. | 120° Azimuth | 58 feet elevation |
| c. | 240° Azimuth | 58 feet elevation |

* Equivalent hours are determined from actual hours using the time-temperature relationships that support the environmental qualification requirements of 10 CFR 50.49.

CONTAINMENT SYSTEMS

CONTAINMENT VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.7 Each containment purge supply and exhaust isolation valve shall be OPERABLE and:

a. The containment purge supply and exhaust isolation valves shall be sealed closed to the maximum extent practicable but may be open for purge system operation for pressure control, for environmental conditions control, for ALARA and respirable air quality considerations for personnel entry and for surveillance tests that require the valve to be open.

b. The purge supply and exhaust isolation valves shall not be opened wider than 33 or 30 degrees, respectively (90 degrees is fully open).

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

ACTION:

a. With a containment purge supply and/or exhaust isolation valve(s) open for reasons other than given in 3.6.1.7.a above, close the open valve(s) or isolate the penetration(s) within 4 hours, otherwise be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With a containment purge supply and/or exhaust isolation valve(s) having a measured leakage rate exceeding the limits of Specification 4.6.1.7.2, restore the inoperable valve(s) to OPERABLE status or isolate the penetrations such that the measured leakage rate does not exceed the limits of Specification 4.6.1.7.2 within 24 hours, otherwise be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7.1 Each containment purge supply and exhaust isolation valve shall be verified to be sealed closed or open in accordance with Specification 3.6.1.7.a ~~at least once per 31 days~~.

4.6.1.7.2 ~~At least once per 6 months~~, each containment purge supply and exhaust isolation valve shall be demonstrated OPERABLE by verifying that the measured leakage rate is less than or equal to 0.05 $L_a$ when pressurized to $P_a$.

4.6.1.7.3 ~~At least once per 18 months~~, the mechanical stop on each containment purge supply and exhaust isolation valve shall be verified to be in place and that the valves will open no more than 33 or 30 degrees, respectively.

Insert 1

CONTAINMENT SYSTEMS

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

CONTAINMENT SPRAY SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.1 Two independent Containment Spray Systems shall be OPERABLE with each Spray System capable of taking suction from the RWST and manually transferring suction to the containment sump via the RHR System.

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

ACTION:

a. With one Containment Spray System inoperable restore the inoperable Spray System to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With two Containment Spray Systems inoperable restore at least one Spray System to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore both Spray Systems to OPERABLE status within 72 hours of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.1 Each Containment Spray System shall be demonstrated OPERABLE:

a. ~~At least once per 31 days~~ by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position and that power is available to flow path components that require power for operation;

b. By verifying that on recirculation flow, each pump develops the indicated differential pressure, when tested pursuant to Specification 4.0.5:

Containment Spray Pump $\geq$241.6 psid while aligned in recirculation mode.

Insert 1

Insert 1

c. ~~At least once per 18 months~~ during shutdown by:

1) Verifying that each automatic valve in the flow path actuates to its correct position on a containment spray actuation test signal, and

2) Verifying that each spray pump starts automatically on a containment spray actuation test signal. The manual isolation valves in the spray lines at the containment shall be locked closed for the performance of these tests.

d. ~~At least once per 10 years~~ by performing an air or smoke flow test through each spray header and verifying each spray nozzle is unobstructed. *

CONTAINMENT SYSTEMS

EMERGENCY CONTAINMENT COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.2 Three emergency containment cooling units shall be OPERABLE.

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

a. With one of the above required emergency containment cooling units inoperable restore the inoperable cooling unit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With two or more of the above required emergency containment cooling units inoperable, restore at least two cooling units to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore all of the above required cooling units to OPERABLE status within 72 hours of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 Each emergency containment cooling unit shall be demonstrated OPERABLE:

a. ~~At least once per 31 days~~ by starting each cooler unit from the control room and verifying that each unit motor reaches the nominal operating current for the test conditions and operates for at least 15 minutes.

b. ~~At least once per 18 months~~ by:

Insert 1

1) Verifying that two emergency containment cooling units start automatically on a safety injection (SI) test signal, and

2) Verifying a cooling water flow rate of greater than or equal to 2000 gpm to each cooler.

## 3/4.6.2.3 RECIRCULATION pH CONTROL SYSTEM

### LIMITING CONDITION FOR OPERATION

3.6.2.3 The Recirculation pH Control System shall be OPERABLE.

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

ACTION:

With the Recirculation pH Control System inoperable, restore the buffering agent to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the next 72 hours.

### SURVEILLANCE REQUIREMENTS

4.6.2.3 The Recirculation pH Control System shall be demonstrated OPERABLE:

a. ~~At least once per 18 months~~ by:

Insert 1

1. Verifying that the buffering agent baskets are in place and intact;

2. Collectively contain ≥ 7500 pounds (154 cubic feet) of sodium tetraborate decahydrate, or equivalent.

Insert 1

SURVEILLANCE REQUIREMENTS (Continued)

4.6.4.2 Each isolation valve shall be demonstrated OPERABLE during the COLD SHUTDOWN or REFUELING MODE ~~at least once per 18 months~~ by:

a. Verifying that on a Phase "A" Isolation test signal, each Phase "A" isolation valve actuates to its isolation position;

b. Verifying that on a Phase "B" Isolation test signal, each Phase "B" isolation valve actuates to its isolation position; and

c. Verifying that on a Containment Ventilation Isolation test signal, each purge, exhaust and instrument air bleed valve actuates to its isolation position.

4.6.4.3 The isolation time of each power-operated or automatic valve shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

PLANT SYSTEMS

AUXILIARY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 Two independent auxiliary feedwater trains including 3 pumps as specified in Table 3.7-3 and associated flowpaths shall be OPERABLE.

~~APPLICABILITY~~: APPLICABILITY MODES 1, 2 and 3

ACTION:

1) With one of the two required independent auxiliary feedwater trains inoperable, either restore the inoperable train to an OPERABLE status within 72 hours, or place the affected unit(s) in at least HOT STANDBY within the next 6 hours* and in HOT SHUTDOWN within the following 6 hours.

2) With both required auxiliary feedwater trains inoperable, within 2 hours either restore both trains to an OPERABLE status, or restore one train to an OPERABLE status and follow ACTION statement 1 above for the other train. If neither train can be restored to an OPERABLE status within 2 hours, verify the OPERABILITY of both standby feed-water pumps and place the affected unit(s) in at least HOT STANDBY within the next 6 hours* and in HOT SHUTDOWN within the following 6 hours. Otherwise, initiate corrective action to restore at least one auxiliary feedwater train to an OPERABLE status as soon as possible and follow ACTION statement 1 above for the other train.

3) With a single auxiliary feedwater pump inoperable, within 4 hours, verify OPERABILITY of two independent auxiliary feedwater trains, or follow ACTION statements 1 or 2 above as applicable. Upon verification of the OPERABILITY of two independent auxiliary feedwater trains, restore the inoperable auxiliary feedwater pump to an OPERABLE status within 30 days, or place the operating unit(s) in at least HOT STANDBY within 6 hours* and in HOT SHUTDOWN within the following 6 hours. The provisions of Specification 3.0.4 are not applicable during the 30 day period for the inoperable auxiliary feedwater pump.

SURVEILLANCE REQUIREMENTS

4.7.1.2.1 The required independent auxiliary feedwater trains shall be demonstrated OPERABLE:

a. ~~At least once per 31 days~~ Insert 1 on a STAGGERED TEST BASIS by:

1) Verifying by control panel indication and visual observation of equipment that each steam turbine-driven pump operates for 15 minutes or greater and develops a flow of greater than or

*If this ACTION applies to both units simultaneously, be in at least HOT STANDBY within the next 12 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS (Continued)

equal to 373 gpm to the entrance of the steam generators. The provisions of Specification 4.0.4 are not applicable for entry into MODES 2 and 3;

2) Verifying by control panel indication and visual observation of equipment that the auxiliary feedwater discharge valves and the steam supply and turbine pressure valves operate as required to deliver the required flow during the pump performance test above;

3) Verifying that each non-automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in its correct position; and

4) Verifying that power is available to those components which require power for flow path operability.

b. ~~At least once per 18 months~~ by:

Insert 1

1) Verifying that each automatic valve in the flow path actuates to its correct position upon receipt of each Auxiliary Feedwater Actuation test signal, and

2) Verifying that each auxiliary feedwater pump receives a start signal as designed automatically upon receipt of each Auxiliary Feedwater Actuation test signal.

4.7.1.2.2 An auxiliary feedwater flow path to each steam generator shall be demonstrated OPERABLE following each COLD SHUTDOWN of greater than 30 days prior to entering MODE 1 by verifying normal flow to each steam generator.

SURVEILLANCE REQUIREMENTS (Continued)

4.7.1.3 The condensate storage tank (CST) system shall be demonstrated OPERABLE ~~at least once per 12 hours~~ by verifying the indicated water volume is within its limit when the tank is the supply source for the auxiliary feedwater pumps~~.~~ *

Insert 1

No change this page, for information only

## SPECIFIC ACTIVITY

### LIMITING CONDITION FOR OPERATION

3.7.1.4 The specific activity of the Secondary Coolant System shall be less than or equal to 0.10 microCurie/gram DOSE EQUIVALENT I-131.

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

ACTION:

With the specific activity of the Secondary Coolant System greater than 0.10 microCurie/gram DOSE EQUIVALENT I-131, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

### SURVEILLANCE REQUIREMENTS

4.7.1.4 The specific activity of the Secondary Coolant System shall be determined to be within the limit by performance of the sampling and analysis program of Table 4.7-1.

TABLE 4.7-1

SECONDARY COOLANT SYSTEM SPECIFIC ACTIVITY

SAMPLE AND ANALYSIS PROGRAM

| TYPE OF MEASUREMENT AND ANALYSIS | SAMPLE AND ANALYSIS FREQUENCY |
|---|---|
| 1. Gross Radioactivity Determination | ~~At least once per 72 hours~~. Insert 1 |
| 2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration | a) Once per 31 days, whenever the gross radioactivity determination indicates concentrations greater than 10% of the allowable limit for radioiodines.<br>b) Once per 6 months, whenever the gross radioactivity determination indicates concentrations less than or equal to 10% of the allowable limit for radioiodines. |

STANDBY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.6 Two Standby Steam Generator Feedwater Pumps shall be OPERABLE* and at least 145,000 gallons of water (indicated volume), shall be in the Demineralized Water Storage Tank.**

APPLICABILITY: MODES 1, 2 and 3

ACTION:

a. With one Standby Steam Generator Feedwater Pump inoperable, restore the inoperable pump to available status within 30 days or submit a SPECIAL REPORT per 3.7.1.6d.

b. With both Standby Steam Generator Feedwater Pumps inoperable, restore at least one pump to OPERABLE status within 24 hours, or:

   1. Notify the NRC within the following 4 hours, and provide cause for the inoperability and plans to restore pump(s) to OPERABLE status and,

   2. Submit a SPECIAL REPORT per 3.7.1.6d.

c. With less than 145,000 gallons of water indicated in the Demineralized Water Storage Tank restore the available volume to at least 145,000 gallons indicated within 24 hours or submit a SPECIAL REPORT per 3.7.1.6d.

d. If a SPECIAL REPORT is required per the above specifications submit a report describing the cause of the inoperability, action taken and a schedule for restoration within 30 days in accordance with 6.9.2.

SURVEILLANCE REQUIREMENTS

4.7.1.6.1 The Demineralized Water Storage tank water volume shall be determined to be within limits ~~at least once per 24 hours.~~ Insert 1

4.7.1.6.2 ~~At least monthly~~ verify the standby feedwater pumps are OPERABLE by testing in recirculation on a STAGGERED TEST BASIS.

Insert 1

4.7.1.6.3 ~~At least once per 18 months~~, verify operability of the respective standby steam generator feedwater pump by starting each pump and providing feedwater to the steam generators.

*These pumps do not require plant safety related emergency power sources for operability and the flowpath is normally isolated.

**The Demineralized Water Storage Tank is non-safety grade.

SURVEILLANCE REQUIREMENTS (Continued)

4.7.1.6.4 The diesel engine for the diesel-driven Standby Steam Generator Feedwater Pump shall be demonstrated OPERABLE:

Insert 1

a. ~~At least once every 31 days~~, by testing with the associated standby steam generator feedwater pump in recirculation.

b. ~~At least once per 18 months~~, by subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for the class of service.

## 3/4.7.1.7 FEEDWATER ISOLATION

### LIMITING CONDITION FOR OPERATION

3.7.1.7 Six Feedwater Control Valves (FCVs) both main and bypass and six Feedwater Isolation Valves (FIVs) both main and bypass shall be OPERABLE.*

APPLICABILITY: MODES 1, 2 and 3**

ACTION:

a. With one or more FCVs inoperable, restore operability, or close or isolate the inoperable FCVs within 72 hours and verify that the inoperable valve(s) is closed or isolated at least once per 7 days or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With one or more FIVs inoperable, restore operability, or close or isolate the inoperable FIV(s) within 72 hours and verify that the inoperable valve(s) is closed or isolated at least once per 7 days or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With one or more bypass valves in different steam generator flow paths inoperable, restore operability, or close or isolate the inoperable bypass valve(s) within 72 hours and verify that the inoperable valve(s) is closed or isolated at least once per 7 days or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

d. With two valves in the same steam generator flow paths inoperable, restore operability, or isolate the affected flowpath within 8 hours or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours..

### SURVEILLANCE REQUIREMENTS

4.7.1.7 Each FCV, FIV and bypass valve shall be demonstrated OPERABLE:

a. ~~At least every 18 months~~ by:

Insert 1

1) Verifying that each FCV, FIV and bypass valve actuates to the isolation position on an actual or simulated actuation signal.

b. In accordance with the Inservice Testing Program by:

1) Verifying that each FCV, FIV and bypass valve isolation time is within limits.

---

*Separate Condition entry is allowed for each valve.

**The provisions of specification 3.0.4 and 4.0.4 are not applicable.

PLANT SYSTEMS

3/4.7.2 COMPONENT COOLING WATER SYSTEM

## LIMITING CONDITION FOR OPERATION

3.7.2 The Component Cooling Water System (CCW) shall be OPERABLE with:

a. Three CCW pumps, and

b. Two CCW heat exchangers.

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

ACTION:

a. With only two CCW pumps with independent power supplies OPERABLE, restore the inoperable CCW pump to OPERABLE status within 30 days or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. The provisions of Specification 3.0.4 are not applicable.

b. With only one CCW pump OPERABLE or with two CCW pumps OPERABLE but not from independent power supplies, restore two pumps from independent power supplies to OPERABLE status within 72 hours or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With less than two CCW heat exchangers OPERABLE, restore two heat exchangers to OPERABLE status within 1 hour or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

## SURVEILLANCE REQUIREMENTS

4.7.2 The Component Cooling Water System (CCW) shall be demonstrated OPERABLE:

a. ~~At least once per 12 hours,~~ by verifying that two heat exchangers and one pump are capable of removing design basis heat loads.

Insert 1

Insert 1

b. ~~At least once per 31 days~~ by: (1) verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position is in its correct position and (2) verifying by a performance test the heat exchanger surveillance curves.*

c. ~~At least once per 18 months~~ during shutdown, by verifying that:

1) Each automatic valve servicing safety-related equipment actuates to its correct position on a SI test signal, and

2) Each Component Cooling Water System pump starts automatically on a SI test signal.

3) Interlocks required for CCW operability are OPERABLE.

*Technical specification 4.7.2.b(2) is not applicable for entry into MODE 4 or MODE 3, provided that:

1) Surveillance 4.7.2.b(2) is performed no later than 72 hours after reaching a Reactor Coolant System Tavg of 547°F, and
2) MODE 2 shall not be entered prior to satisfactory performance of this surveillance.

PLANT SYSTEMS

3/4.7.3 INTAKE COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 The Intake Cooling Water System (ICW) shall be OPERABLE with:

a. Three ICW pumps, and
b. Two ICW headers.

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

ACTION:

a. With only two ICW pumps with independent power supplies OPERABLE, restore the inoperable ICW pump to OPERABLE status within 14 days or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. The provisions of Specification 3.0.4 are not applicable. *

b. With only one ICW pump OPERABLE or with two ICW pumps OPERABLE but not from independent power supplies, restore two pumps from independent power supplies to OPERABLE status within 72 hours or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With only one ICW header OPERABLE, restore two headers to OPERABLE status within 72 hours or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.3 The Intake Cooling Water System (ICW) shall be demonstrated OPERABLE:

Insert 1

a. ~~At least once per 31 days~~ by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position is in its correct position; and

b. ~~At least once per 18 months~~ during shutdown, by verifying that:

1) Each automatic valve servicing safety-related equipment actuates to its correct position on a SI test signal, and

2) Each Intake Cooling Water System pump starts automatically on a SI test signal.

3) Interlocks required for system operability are OPERABLE.

PLANT SYSTEMS

3/4.7.4 ULTIMATE HEAT SINK

LIMITING CONDITION FOR OPERATION

3.7.4 The ultimate heat sink shall be OPERABLE with an average supply water temperature less than or equal to 100°F.

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

ACTION:

With the requirements of the above specification not satisfied, be in at least HOT STANDBY within 12 hours and In COLD SHUTDOWN within the following 30 hours. This ACTION shall be applicable to both units simultaneously.

SURVEILLANCE REQUIREMENTS

4.7.4 The ultimate heat sink shall be determined OPERABLE ~~at least once per 24 hours~~ by verifying the average supply water temperature* to be within its limit.

Insert 1

*Portable monitors may be used to measure the temperature.

3/4.7.5 CONTROL ROOM EMERGENCY VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION (continued)

b. With the Control Room Emergency Ventilation System inoperable due to an inoperable CRE boundary, immediately suspend all movement of irradiated fuel in the spent fuel pool, and immediately initiate action to implement mitigating actions, and within 24 hours, verify mitigating actions ensure CRE occupant radiological and chemical hazards will not exceed limits, and CRE occupants are protected from smoke hazards, and restore CRE boundary to OPERABLE status within 90 days, or:

1) With the requirements not met, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

2) If this ACTION applies to both units simultaneously, be in HOT STANDBY within 12 hours and in COLD SHUTDOWN within the following 30 hours.

MODES 5 and 6:

c. With the Control Room Emergency Ventilation System inoperable++, immediately suspend all operations involving CORE ALTERATIONS, movement of irradiated fuel in the spent fuel pool, or positive reactivity changes. This ACTION shall apply to both units simultaneously.

SURVEILLANCE REQUIREMENTS

4.7.5 The Control Room Emergency Ventilation System shall be demonstrated OPERABLE:

Insert 1

a. ~~At least once per 12 hours~~ by verifying that the control room air temperature is less than or equal to 120°F;

b. ~~At least once per 31 days~~ by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the system operates for at least 15 minutes***;

c. ~~At least once per 18 months~~ or (1) after 720 hours of system operation, or (2) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (3) following exposure of the filters to effluents from painting, fire, or chemical release in any ventilation zone communicating with the system that may have an adverse effect on the functional capability of the system, or (4) after complete or partial replacement of a filter bank by:

++ If action per ACTIONS a.4, a.6, a.7, a.8, or a.9 is taken that permits indefinite operation and the system is placed in recirculation mode, then CORE ALTERATIONS, movement of irradiated fuel in the spent fuel pool, and positive reactivity changes may resume.

***As the mitigation actions of TS 3.7.5 Action a.5 may include the use of the compensatory filtration unit, the unit shall meet the surveillance requirements of TS 4.7.5.b, by manual initiation from outside the control room and TS 4.7.5.c and d.

1) Verifying that the air cleanup system satisfies the in-place penetration and bypass leakage testing acceptance criteria of greater than or equal to 99% DOP and halogenated hydrocarbon removal at a system flow rate of 1000 cfm ±10%***.

2) Verifying, within 31 days after removal, that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, and analyzed per ASTM D3803 - 1989 at 30°C and 95% relative humidity, meets the methyl iodide penetration criteria of less than 2.5% or the charcoal be replaced with charcoal that meets or exceeds the stated performance requirement***, and

3) Verifying by a visual inspection the absence of foreign materials and gasket deterioration***.

d.1 ~~At least once per 12 months~~ by verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches Water Gauge while operating the system at a flow rate of 1000 cfm ±10%***;

d.2 On STAGGERED TEST BASIS ~~every 36 months,~~ test the supply fans (trains A and B) and measure CRE pressure relative to external areas adjacent to the CRE boundary.

Insert 1

e. At least once ~~per 18 months by verifying tha~~t on a Containment Phase "A" Isolation test signal the system automatically switches into the recirculation mode of operation,

f. At least once ~~per 18 months by verifying o~~perability of the kitchen and toilet area exhaust dampers, and

g. By performing required CRE unfiltered air inleakage testing in accordance with the Control Room Envelope Habitability Program.

***As the mitigation actions of TS 3.7.5 Action a.5 may include the use of the compensatory filtration unit, the unit shall meet the surveillance requirements of TS 4.7.5.b, by manual initiation from outside the control room and TS 4.7.5.c and d.

## 3/4.7.7 SEALED SOURCE CONTAMINATION

### LIMITING CONDITION FOR OPERATION

3.7.7 Each sealed source containing radioactive material either in excess of 100 microCuries of beta and/or gamma emitting material or 5 microCuries of alpha emitting material shall be free of greater than or equal to 0.005 microCurie of removable contamination.

APPLICABILITY: At all times.

ACTION:

a. With a sealed source having removable contamination in excess of the above limits, immediately withdraw the sealed source from use and either:

   1. Decontaminate and repair the sealed source, or

   2. Dispose of the sealed source in accordance with Commission Regulations.

b. The provisions of Specification 3.0.3 are not applicable.

### SURVEILLANCE REQUIREMENTS

4.7.7.1 Test Requirements - Each sealed source shall be tested for leakage and/or contamination by:

a. The licensee, or

b. Other persons specifically authorized by the Commission or an Agreement State.

The test method shall have a detection sensitivity of at least 0.005 microCurie per test sample.

4.7.7.2 Test Frequencies - Each category of sealed sources (excluding startup sources and fission detectors previously subjected to core flux) shall be tested at the frequency described below.

a. Sources in use - ~~At least once per 6 months~~ for all sealed sources containing radioactive materials:

   1) With a half-life greater than 30 days (excluding Hydrogen 3), and

   2) In any form other than gas.

Insert 1

Insert 1

SURVEILLANCE REQUIREMENTS

4.8.1.1.1 Each of the above required startup transformers and their associated circuits shall be:

a. Determined OPERABLE ~~at least once per 7 days~~ by verifying correct breaker alignments, indicated power availability, and

b. Demonstrated OPERABLE ~~at least once per 18 months~~ while shutting down, by transferring manually unit power supply from the auxiliary transformer to the startup transformer.

SURVEILLANCE REQUIREMENTS (Continued)

4.8.1.1.2 Each diesel generator shall be demonstrated OPERABLE*:

a. ~~At least once per 31 days~~ on a STAGGERED TEST BASIS by:

Insert 1

1) Verifying the fuel volume in the day and skid-mounted fuel tanks (Unit 4-day tank only),

2) Verifying the fuel volume in the fuel storage tank,

3) Verifying the lubricating oil inventory in storage,

4) Verifying the diesel starts and accelerates to reach a generator voltage and frequency of 3950-4350 volts and 60 $\pm$ 0.6 Hz. Once per 184 days, these conditions shall be reached within 15 seconds after the start signal fro m normal conditions. For all other starts, warmup procedures, such as idling and gradual acceleration as recommended by the manufacturer may be used. The diesel generator shall be started for this test by using one of the following signals:

a) Manual, or

b) Simulated loss-of-offsite power by itself, or

c) Simulated loss-of-offsite power in conjunction with an ESF Actuation test signal, or

d) An ESF Actuation test signal by itself.

5) Verifying the generator is synchronized, loaded** to 2300 - 2500 kW (Unit 3), 2650-2850 kW (Unit 4)***, operates at this loaded condition for at least 60 minutes and for Unit 3 until automatic transfer of fuel from the day tank to the skid mounted tank is demonstrated, and the cooling system is demonstrated OPERABLE.

6) Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

* All diesel generator starts for the purpose of these surveillances may be proceeded by a prelube period as recommended by the manufacturer.

** May include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized.

***Momentary transients outside these load bands do not invalidate this test.

Insert 1

SURVEILLANCE REQUIREMENTS (Continued)

b. Demonstrating ~~at least once per 92 days~~ that a fuel transfer pump starts automatically and transfers fuel from the storage system to the day tank,

c. ~~At least once per 31 days~~ and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by checking for and removing accumulated water from the day and skid-mounted fuel tanks (Unit 4-day tank only);

d. ~~At least once per 31 days~~ by checking for and removing accumulated water from the fuel oil storage tanks;

Insert 1

e. By verifying fuel oil properties of new fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.

f. By verifying fuel oil properties of stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.

g. ~~At least once per 18 months~~, during shutdown (applicable to only the two diesel generators associated with the unit):

1) Deleted

2)* Verifying the generator capability to reject a load of greater than or equal to 380 kw while maintaining voltage at 3950-4350 volts and frequency at 60 ± 0.6 Hz; *

3)* Verifying the generator capability to reject a load of greater than or equal to 2500 kW (Unit 3), 2874 kW (Unit 4) without tripping. The generator voltage shall return to less than or equal to 4784 volts within 2 seconds following the load rejection;

4) Simulating a loss-of-offsite power by itself, and:

a) Verifying deenergization of the emergency busses and load shedding from the emergency busses, and

b. Verifying the diesel starts on the auto-start signal, energizes the emergency busses with any permanently

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* For the purpose of this test, warmup procedures, such as idling, gradual acceleration, and gradual loading as recommended by the manufacturer may be used.

No change this page,
for information only



connected loads within 15 seconds, energizes the auto–connected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the auto-connected shutdown loads. After automatic load sequencing, the steady-state voltage and frequency of the emergency busses shall be maintained at 3950-4350 volts and 60 ± 0.6 Hz during this test.

5) Verifying that on an ESF Actuation test signal, without loss-of-offsite power, the diesel generator starts on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 3950-4350 volts and 60 ± 0.6 Hz within 15 seconds after the auto-start signal; the steady-state generator voltage and frequency shall be maintained within these limits during this test;

6) Simulating a loss-of-offsite power in conjunction with an ESF Actuation test signal, and:

a) Verifying deenergization of the emergency busses and load shedding from the emergency busses;

b) Verifying the diesel starts on the auto-start signal; energizes the emergency busses with any permanently connected loads within 15 seconds, energizes the auto-connected emergency (accident) loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After automatic load sequencing, the steady-state voltage and frequency of the emergency busses shall be maintained at 3950-4350 volts and 60 ± 0.6 Hz during this test; and

c) Verifying that diesel generator trips that are made operable during the test mode of diesel operation are inoperable.

7)* # Verifying the diesel generator operates for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to 2550-2750 kW (Unit 3), 2950-3150 kW (Unit 4)** and during the remaining 22 hours of this test, the diesel generator shall be loaded to 2300-2500 kW (Unit 3), 2650-2850 kW (Unit 4)**. The generator voltage and frequency shall be 3950-4350 volts and 60 ± 0.6 Hz within 15 seconds after the start signal; the steady-state generator voltage and frequency

* For the purpose of this test, warmup procedures, such as idling, gradual acceleration, and gradual loading as recommended by the manufacturer may be used.

** Momentary transients outside these load bands do not invalidate this test.

# This test may be performed during POWER OPERATION

No change this page, for information only

ELECTRICAL POWER SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

shall be maintained within these limits during this test. Within 5 minutes after completing this 24-hour test, verify the diesel starts and accelerates to reach a generator voltage and frequency of 3950-4350 volts and 60 ± 0.6 Hz within 15 seconds after the start signal.**

8) Verifying that the auto-connected loads to each diesel generator do not exceed 2500 kW (Unit 3), 2874 kW (Unit 4);

9) Verifying the diesel generator's capability to:

a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

b) Transfer its loads to the offsite power source, and

c) Be restored to its standby status.

10) Verifying that the diesel generator operating in a test mode, connected to its bus, a simulated Safety Injection signal overrides the test mode by: (1) returning the diesel generator to standby operation, and (2) automatically energizing the emergency loads with offsite power;

11) Verifying that the fuel transfer pump transfers fuel from the fuel storage tank (Unit 3), fuel storage tanks (Unit 4) to the day tanks of each diesel associated with the unit via the installed cross-connection lines;

12) Verifying that the automatic load sequence timer is OPERABLE with the interval between each load block within ± 10% of its design interval;

13) Verifying that the diesel generator lockout relay prevents the diesel generator from starting;

** If verification of the diesel's ability to restart and accelerate to a generator voltage and frequency of 3950-4350 volts and 60 ± 0.6 Hz within 15 seconds following the 24 hour operation test of Specification 4.8.1.1.2.g.7) is not satisfactorily completed, it is not necessary to repeat the 24-hour test. Instead, the diesel generator may be operated between 2300-2500 kW Unit 3, 2650-2850 kW (Unit 4) for 2 hours or until operating temperature has stabilized (whichever is greater). Following the 2 hours/operating temperature stabilization run, the EDG is to be secured and restarted within 5 minutes to confirm its ability to achieve the required voltage and frequency within 15 seconds.

Insert 1

h. ~~At least once per 10 years~~ or after any modifications which could affect diesel generator interdependence by starting all required diesel generators simultaneously and verifying that all required diesel generators provide 60 ± 0.6 Hz frequency and 3950-4350 volts in less than or equal to 15 seconds: and

I. ~~At least once per 10 years~~ by:

1) Draining each fuel oil storage tank, removing the accumulated sediment and cleaning the tank.*

2) For Unit 4 only, performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda.

4.8.1.1.3 Reports - (Not Used)

* A temporary Class III fuel storage system containing a minimum volume of 38,000 gallons of fuel oil may be used for up to 10 days during the performance of Surveillance Requirement 4.8.1.1.2i.1 for the Unit 3 storage tank while Unit 3 is in Modes 5, 6, or defueled. If the diesel fuel oil storage tank is not returned to service within 10 days, Technical Specification 3.8.1.1 Action b and 3.8.1.2 Action apply to Unit 4 and Unit 3 respectively.

LIMITING CONDITION FOR OPERATION

ACTION: (Continued)

b. With one of the required battery banks inoperable, or with none of the full-capacity chargers associated with a battery bank OPERABLE, restore all battery banks to OPERABLE status and at least one charger associated with each battery bank to OPERABLE status within two hours* or be in at least HOT STANDBY within the next 12 hours and in COLD SHUTDOWN within the following 30 hours. This ACTION applies to both units simultaneously.

SURVEILLANCE REQUIREMENTS

4.8.2.1 Each 125-volt battery bank and its associated full capacity charger(s) shall be demonstrated OPERABLE:

a. ~~At least once per 7 days~~ by verifying that:

1) The parameters in Table 4.8-2 meet the Category A limits, and

2) The total battery terminal voltage is greater than or equal to 129 volts on float charge and the battery charger(s) output voltage is ≥ 129 volts, and

3) If two battery chargers are connected to the battery bank, verify each battery charger is supplying a minimum of 10 amperes, or demonstrate that the battery charger supplying less than 10 amperes will accept and supply the D.C. bus load independent of its associated battery charger.

b. ~~At least once per 92 days~~ and within 7 days after a battery discharge with battery terminal voltage below 105 volts (108.6 volts for spare battery D-52), or battery overcharge with battery terminal voltage above 143 volts, by verifying that:

Insert 1

1) The parameters in Table 4.8-2 meet the Category B limits,

2) The average electrolyte temperature of every sixth cell is above 60°F, and

3) There is no visible corrosion at either terminals or connectors, or verify battery connection resistance is:

| | | |
|---|---|---|
| Battery<br>3B, 4A | Connection<br>inter-cell / termination<br>inter-cell (brace locations)<br>transition cables<br>or<br>total battery connections | Limit (Micro-Ohms)<br>≤ 29<br>≤ 30<br>≤ 125<br><br>≤ 1958 |
| Battery<br>3A, 4B, D-52 | Connection<br>inter-cell / termination<br>inter-cell (brace locations)<br>transition cables<br>or<br>total battery connections | Limit (Micro-Ohms)<br>≤ 35<br>≤ 40<br>≤ 125<br><br>≤ 2463 |

c. ~~At least once per 18 months~~ by verifying that:

1) The cells, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration,

*Can be extended to 24 hours if the oppsite unit is in MODE 5 or 6 and each of the remaining required battery chargers is capable of being powered from its associated diesel generator(s).

SURVEILLANCE REQUIREMENTS (Continued)

2) The cell-to-cell and terminal connections are clean, tight, and coated with anticorrosion material,

3) Each 400 amp battery charger (associated with Battery Banks 3A and 4B) will supply at least 400 amperes at ≥ 129 volts for at least 8 hours, and each 300 amp battery charger (associated with Battery Banks 3B and 4A) will supply at least 300 amperes at ≥ 129 volts for at least 8 hours, and

4) Battery Connection resistance is:

| | | |
|---|---|---|
| Battery<br>3B, 4A | Connection<br>inter-cell / termination<br>inter-cell (brace locations)<br>transition cables<br>or<br>total battery connections | Limit (Micro-Ohms)<br>≤ 29<br>≤ 30<br>≤ 125<br><br>≤ 1958 |
| Battery<br>3A, 4B, D-52 | Connection<br>inter-cell / termination<br>inter-cell (brace locations)<br>transition cables<br>or<br>total battery connections | Limit (Micro-Ohms)<br>≤ 35<br>≤ 40<br>≤ 125<br><br>≤ 2463 |

d. ~~At least once per 18 months~~, during shutdown**, by verifying that the battery capacity is adequate to supply and maintain in OPERABLE status all of the actual or simulated emergency loads for the design duty cycle when the battery is subjected to a battery service test.

Insert 1

e. At least once per 12 months, during shutdown**, by giving performance discharge tests of battery capacity to any battery that shows signs of degradation or has reached 85% [75% for Batteries 4B and D52 (Spare) when used in place of Battery 4B] of service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% [7% for Batteries 4B and D52 (Spare) when used in place of Battery 4B] of rated capacity from its average on previous performance tests, or is below 90% [93% for Batteries 4B and D52 (Spare) when used in place of Battery 4B] of the manufacturer's rating.

f. ~~At least once per 60 months,~~ during shutdown**, by verifying that the battery capacity is at least 80% [87% for Batteries 4B and D52 (Spare) when used in place of Battery 4B] of the manufacturer's rating when subjected to a performance discharge test. Once per 60-month interval this performance discharge test may be performed in lieu of the battery service test required by Specification 4.8.2.1.d.

**Except that the spare battery bank D-52, and any other battery out of service when spare battery bank D-52 is in service may be tested with simulated loads during operation.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

within 24 hours or be in at least HOT STANDBY within the next 12 hours and in COLD SHUTDOWN within the following 30 hours. This ACTION applies to both units simultaneously.

d. With one D.C. bus not energized from its associated battery bank or associated charger, reenergize the D.C. bus from its associated battery bank within 2 hours* or be in at least HOT STANDBY within the next 12 hours and in COLD SHUTDOWN within the following 30 hours. This ACTION applies to both units simultaneously.

SURVEILLANCE REQUIREMENTS

4.8.3.1 The specified busses shall be determined energized and aligned in the required manner ~~at least once per 7 days~~ by verifying correct breaker alignment and indicated voltage on the busses.

Insert 1

* Can be extended to 24 hours if the opposite unit is in MODE 5 or 6 and each of the remaining required battery chargers is capable of being powered from its associated diesel generator(s).

ONSITE POWER DISTRIBUTION

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.3.2 As a minimum, the following electrical busses shall be energized in the specified manner:

a. One train of A.C. emergency busses associated with the unit (3.8.3.1a. or b.) consisting of one 4160-volt and three 480-volt A.C. emergency busses load centers* and three (four for Unit 4 Train A) vital sections of motor control center busses,

b. Two 120-volt A.C. vital busses for the unit energized from their associated inverters** connected to their respective D.C. busses, and

c. Three 125-volt D.C. busses energized from their associated battery banks.

APPLICABILITY MODES 5*** and 6***.

ACTION:

With any of the above required electrical busses not energized in the required manner, immediately suspend all operations involving CORE ALTERATIONS, positive reactivity changes, or movement of irradiated fuel, initiate corrective action to energize the required electrical busses in the specified manner as soon as possible, and within 8 hours, depressurize and vent the RCS through at least a 2.2 square inch vent.

SURVEILLANCE REQUIREMENTS

4.8.3.2 The specified busses shall be determined energized in the required manner ~~at least once per 7 days~~ by verifying correct breaker alignment and indicated voltage on the busses.

Insert 1

*With the opposite unit in MODE 1, 2, 3, or 4, the 480-volt load centers can only be cross-tied upon issuance of an engineering evaluation to prevent exceeding required electrical components maximum design ratings and to ensure availability of the minimum required equipment.

**A backup inverter may be used to replace the normal inverter provided the normal inverter on the same DC bus for the opposite unit is not replaced at the same time.

***CAUTION - If the opposite unit is in MODES 1, 2, 3, or 4, see the corresponding Limiting Condition for Operation 3.8.3.1.

3/4.9 REFUELING OPERATIONS

3/4.9.1 BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.9.1 The boron concentration of all filled portions of the Reactor Coolant System and the refueling canal shall be maintained uniform and sufficient to ensure that the more restrictive of the following reactivity conditions is met; either:

a. A $K_{eff}$ of 0.95 or less, or

b. A boron concentration of greater than or equal to 2300 ppm.

APPLICABILITY: MODE 6.*

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at greater than or equal to 16 gpm of a solution containing greater than or equal to 3.0 wt% (5245 ppm) boron or its equivalent until $K_{eff}$ is reduced to less than or equal to 0.95 or the boron concentration is restored to greater than or equal to 2300 ppm, whichever is the more restrictive.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The more restrictive of the above two reactivity conditions shall be determined prior to:

a. Removing or unbolting the reactor vessel head, and

b. Withdrawal of any full-length control rod in excess of 3 feet from its fully inserted position within the reactor vessel.

4.9.1.2 The boron concentration of the Reactor Coolant System and the refueling canal shall be determined by chemical analysis ~~at least once per 72 hours~~.

4.9.1.3 Valves isolating unborated water sources** shall be verified closed and secured in position by mechanical stops or by removal of air or electrical power ~~at least once per 31 days~~.

Insert 1

* The reactor shall be maintained in MODE 6 whenever fuel is in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

** The primary water supply to the boric acid blender may be opened under administrative controls for makeup.

REFUELING OPERATIONS

3/4.9.2 INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.9.2 As a minimum, one primary Source Range Neutron Flux Monitor with continuous visual indication in the control room and audible indication in the containment and control room, and one of the remaining three Source Range Neutron Flux Monitors (one primary or one of the two backup monitors) with continuous visual indication in the control room shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTION:

a. With one of the above required monitors inoperable or not operating, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

b. With both of the above required monitors inoperable or not operating, determine the boron concentration of the Reactor Coolant System at least once per 12 hours.

SURVEILLANCE REQUIREMENTS

4.9.2 Each required Source Range Neutron Flux Monitor shall be demonstrated OPERABLE by performance of:

a. A CHANNEL CHECK ~~at least once per 12 hours,~~

b. An ANALOG CHANNEL OPERATIONAL TEST within 8 hours prior to the initial start of CORE ALTERATIONS, and

c. An ANALOG CHANNEL OPERATIONAL TEST ~~at least once per 7 days.~~

Insert 1

3/4.9.8 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.8.1 At least one residual heat removal (RHR) loop shall be OPERABLE and in operation.*

APPLICABILITY: MODE 6, when the water level above the top of the reactor vessel flange is greater than or equal to 23 feet.

ACTION:

With no RHR loop OPERABLE and in operation, suspend all operations involving an increase in the reactor decay heat load or a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required RHR loop to OPERABLE and operating status as soon as possible. Close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere within 4 hours.

SURVEILLANCE REQUIREMENTS

4.9.8.1.1 At least one RHR loop shall be verified in operation and circulating reactor coolant at a flow rate of greater than or equal to 3000 gpm ~~at least once per 12 hours~~.

4.9.8.1.2 The RHR flow indicator shall be subjected to a CHANNEL CALIBRATION ~~at least once per 18 months.~~

Insert 1

*The required RHR loop may be removed from operation for up to 1 hour per 8 hour period, provided no operations are permitted that would cause reduction of the Reactor Coolant System boron concentration.

REFUELING OPERATIONS

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.8.2 Two independent residual heat removal (RHR) loops shall be OPERABLE, and at least one RHR loop shall be in operation*.

APPLICABILITY: MODE 6, when the water level above the top of the reactor vessel flange is less than 23 feet.

ACTION:

a. With less than the required RHR loops OPERABLE, immediately initiate corrective action to return the required RHR loops to OPERABLE status, or to establish greater than or equal to 23 feet of water above the reactor vessel flange, as soon as possible.

b. With no RHR loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required RHR loop to operation. Close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere within 4 hours.

SURVEILLANCE REQUIREMENTS

4.9.8.2 At least one RHR loop shall be verified in operation and circulating reactor coolant at a flow rate of greater than or equal to 3000 gpm ~~at least once per 12 hours~~.

Insert 1

* One required RHR loop may be inoperable for up to 2 hours for surveillance testing, provided that the other RHR loop is OPERABLE and in operation.

REFUELING OPERATIONS

3/4.9.11 WATER LEVEL - STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.11 The water level shall be maintained greater than or equal to elevation 56' - 10" the spent fuel storage pool.*

APPLICABILITY: Whenever irradiated fuel assemblies are in the storage pool.

ACTION:

a. With the requirements of the above specification not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the fuel storage areas and restore the water level to within its limit within 4 hours.

b. The provisions of Specification 3.0.3 are not applicable.

Insert 1

SURVEILLANCE REQUIREMENTS

4.9.11 The water level in the storage pool shall be determined to be at least its minimum required depth ~~at least once per 7 days~~ when irradiated fuel assemblies are in the fuel storage pool.

*The requirements of this specification may be suspended for more than 4 hours to perform maintenance provided a 10 CFR 50.59 evaluation is prepared prior to suspension of the above requirement and all movement of fuel assemblies and crane operation with loads in the fuel storage areas are suspended. If the level is not restored within 7 days, the NRC shall be notified within the next 24 hours.

## 3/4.9.14 SPENT FUEL STORAGE

### LIMITING CONDITION FOR OPERATION

3.9.14 The following conditions shall apply to spent fuel storage:

a. The minimum boron concentration in the Spent Fuel Pit shall be 2300 ppm.

b. The combination of initial enrichment, burnup, and cooling time of each fuel assembly stored in the Spent Fuel Pit shall be in accordance with Specification 5.5.1.

APPLICABILITY: At all times when fuel is stored in the Spent Fuel Pit.

ACTION:

a. With boron concentration in the Spent Fuel Pit less than 2300 ppm, suspend movement of spent fuel in the Spent Fuel Pit and initiate action to restore boron concentration to 2300 ppm or greater.

b. With condition b not satisfied, suspend movement of additional fuel assemblies into the Spent Fuel Pit and restore the spent fuel storage configuration to within the specified conditions.

c. The provisions of Specification 3.0.3 are not applicable.

### SURVEILLANCE REQUIREMENTS

4.9.14.1 The boron concentration of the Spent Fuel Pit shall be verified to be 2300 ppm or greater ~~at least once per month~~.

4.9.14.2 A representative sample of inservice Metamic inserts shall be visually inspected in accordance with the Metamic Surveillance Program described in UFSAR Section 16.2. The surveillance program ensures that the performance requirements of Metamic are met over the surveillance interval.

Insert 1

SPECIAL TEST EXCEPTIONS

3/4.10.3 PHYSICS TESTS

LIMITING CONDITION FOR OPERATION

3.10.3 The limitations of Specifications 3.1.1.3, 3.1.1.4, 3.1.3.1, 3.1.3.5, and 3.1.3.6 may be suspended during the performance of PHYSICS TESTS provided:

a. The THERMAL POWER does not exceed 5% of RATED THERMAL POWER,

b. The Reactor Trip Setpoints on the OPERABLE Intermediate and Power Range channels are set at less than or equal to 25% of RATED THERMAL POWER, and

c. The Reactor Coolant System lowest operating loop temperature ($T_{avg}$) is greater than or equal to 531°F.

APPLICABILITY: MODE 2.

ACTION:

a. With the THERMAL POWER greater than 5% of RATED THERMAL POWER, immediately open the Reactor trip breakers.

b. With a Reactor Coolant System operating loop temperature ($T_{avg}$) less than 531°F, restore $T_{avg}$ to within its limit within 15 minutes or be in at least HOT STANDBY within the next 15 minutes.

SURVEILLANCE REQUIREMENTS

4.10.3.1 The THERMAL POWER shall be determined to be less than or equal to 5% of RATED THERMAL POWER ~~at least once per hour~~ during PHYSICS TESTS.

4.10.3.2 Each Intermediate and Power Range channel shall be subjected to an ANALOG CHANNEL OPERATIONAL TEST within 12 hours prior to initiating PHYSICS TESTS.

4.10.3.3 The Reactor Coolant System temperature ($T_{avg}$) shall be determined to be greater than or equal to 531°F ~~at least once per 30 minutes~~ during PHYSICS TESTS.

Insert 1

3. If crack indications are found in any portion of a SG tube not excluded above, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary-secondary leakage.

k. Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation System (CREVS), CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident.

The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

d. Measurement, at designated locations, of the CRE pressure relative to external areas adjacent to the CRE boundary during the pressurization mode of operation of the CREVS, operating at the flow rate required by Surveillance Requirement 4.7.5.d, at a Frequency of 18 months. Additionally, the supply fans (trains A and B) will be tested on a staggered test basis (defined in Technical Specification definition 1.29 every 36 months). The results shall be trended and the CRE boundary assessed every 18 months.

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

Insert 2

f. The provisions of Specification 4.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

6.8.5 DELETED

# Attachment 4

# Turkey Point Nuclear Plant
# License Amendment Request No. LAR-229

## Technical Specifications Bases
## Marked-Up Pages

## For Information Only

**This coversheet plus 19 pages.**

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**Technical Specification Bases**
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3/4.1.3 (Continued)

TS 3.1.3.2 Action a.2.c) requires the use of the Movable Incore Detector System to verify rod position prior to increasing thermal power above 50 percent Rated Thermal Power (RTP) and within 8 hours of reaching 100 percent RTP. These provisions are intended to establish and confirm the position of the rod with the inoperable RPI to ensure that power distribution requirements are **NOT** violated.

The ACTION Statements which permit limited variations from the basic requirements are accompanied by additional restrictions which ensure that the original design criteria are met. Misalignment of a rod requires measurement of peaking factors and a restriction in THERMAL POWER. These restrictions provide assurance of fuel rod integrity during continued operation. In addition, those safety analyses affected by a misaligned rod are reevaluated to confirm that the results remain valid during future operation.

The maximum rod drop time restriction is consistent with the assumed rod drop time used in the safety analyses. Measurement with Tavg greater than or equal to 500°F and with all Reactor Coolant Pumps operating ensures that the measured drop times will be representative of insertion times experienced during a Reactor Trip at operating conditions.

Control rod positions and OPERABILITY of the Rod Position Indicators are required to be verified on a nominal basis ~~of once per 12 hours~~ with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCOs are satisfied.

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3/4.2.5 DNB Parameters

The limits on the DNB-related parameters assure that each of the parameters are maintained within the normal steady-state envelope of operation assumed in the transient and accident analyses. The limits are consistent with the initial UFSAR assumptions and have been analytically demonstrated adequate to maintain a minimum DNBR above the applicable design limits throughout each analyzed transient. The limits for Tavg and pressurizer pressure have been moved to the COLR. The measured RCS flow value of 270,000 gpm corresponds to a Thermal Design Flow of 260,700 gpm with an allowance of 3.5% to accommodate calorimetric measurement uncertainty.

The ~~12-hour~~ periodic surveillance of these parameters through instrument readout is sufficient to ensure that the parameters are restored within their limits following load changes and other expected transient operation. The ~~18-month~~ periodic measurement of the RCS total flow rate is adequate to ensure that the DNB-related flow assumption is met and to ensure correlation of the flow indication channels with measured flow. The indicated percent flow surveillance ~~on a 12-hour basis~~ will provide sufficient verification that flow degradation has **NOT** occurred. An indicated percent flow which is greater than the thermal design flow plus instrument channel inaccuracies and parallax errors is acceptable for the ~~12-hour~~ surveillance on RCS flow. To minimize measurement uncertainties it is assumed that the RCS flow channel outputs are averaged.

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3/4.3 Instrumentation

3/4.3.1
&
3/4.3.2 Reactor Trip System and Engineered Safety Features Actuation System Instrumentation

The OPERABILITY of the Reactor Trip System and the Engineered Safety Features Actuation System instrumentation and interlocks ensures that: (1) The associated ACTION and/or Reactor trip will be initiated when the parameter monitored by each channel or combination thereof reaches its Setpoint (2) The specified coincidence logic is maintained, (3) Sufficient redundancy is maintained to permit a channel to be out of-service for testing or maintenance (due to plant specific design, pulling fuses and using jumpers may be used to place channels in trip), and (4) Sufficient system functional capability is available from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundancy, and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the safety analyses. The Surveillance Requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests ~~performed at the minimum frequencies~~ are sufficient to demonstrate this capability. Surveillances for the analog RPS/ESFAS Protection and Control rack instrumentation have been extended ~~to quarterly~~ in accordance with WCAP-10271, Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System, and supplements to that report as generically approved by the NRC and documented in their SERs (Letters to the Westinghouse Owner's Group from the NRC dated February 21, 1985, February 22, 1989, and April 30, 1990).

Under some pressure and temperature conditions, certain surveillances for Safety Injection cannot be performed because of the system design. Allowance to change modes is provided under these conditions as long as the surveillances are completed within specified time requirements.

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3/4.4.2 (Continued)

In MODE 5 only one Pressurizer Code Safety is required for overpressure protection. In lieu of an actual OPERABLE Code Safety Valve, an unisolated and unsealed vent pathway (i.e., a direct, unimpaired opening, a vent pathway with valves locked open and/or power removed and locked on an open valve) of equivalent size can be taken credit for as synonymous with an OPERABLE Code Safety.

Demonstration of the safety valves lift settings will occur only during shutdown and will be performed in accordance with the provisions of the ASME OM Code. The Pressurizer Code Safety Valves lift settings allows a +2%, -3% setpoint tolerance for OPERABILITY; however, the valves are reset to within ±1% during the surveillance to allow for drift.

3/4.4.3 Pressurizer

The ~~12-hour~~ periodic surveillance is sufficient to ensure that the maximum water volume parameter is restored to within its limit following expected transient operation. The maximum water volume (1133 cubic feet) ensures that a steam bubble is formed and thus the RCS is **NOT** a hydraulically solid system. The requirement that both backup pressurizer heater groups be OPERABLE enhances the capability of the plant to control Reactor Coolant System pressure and establish natural circulation.

3/4.4.4 Relief Valves

The opening of the power-operated relief valves (PORVs) fulfills **NO** safety-related function and **NO** credit is taken for their operation in the safety analysis for MODE 1, 2 or 3. Equipment necessary to establish PORV operability in Modes 1 and 2 is limited to Vital DC power and the Instrument Air system. Equipment necessary to establish block valve operability is limited to an AC power source. Each PORV has a remotely operated block valve to provide a positive shutoff capability should a PORV fail in the open position.

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3/4.4.6.2 (Continued)

Action d.

With one or more RCS Pressure Isolation Valves with leakage greater than 5 gpm, the leakage must be reduced to below 5 gpm within 1 hour or the reactor must be brought to at least HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours.

The allowable outage times 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. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

Surveillance Requirements

SR 4.4.6.2.1

Verifying Reactor Coolant System leakage to be within the LCO limits ensures the integrity of the Reactor Coolant Pressure Boundary is maintained. PRESSURE BOUNDARY LEAKAGE would at first appear as UNIDENTIFIED LEAKAGE and can only be positively identified by inspection. It should be noted that leakage past seals and gaskets is **NOT** PRESSURE BOUNDARY LEAKAGE. UNIDENTIFIED LEAKAGE and IDENTIFIED LEAKAGE are determined by performance of a Reactor Coolant System water inventory balance.

a. & b.

These SRs demonstrate that the RCS operational leakage is within the LCO limits by monitoring the containment atmosphere gaseous or particulate radioactivity monitor and the containment sump level ~~at least once per 12 hours~~.

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3/4.4.6.2 (Continued)

c.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions and near operating pressure. The Surveillance is modified by two notes. Note *** states that this SR is **NOT** required to be performed until 12 hours after establishment of steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Steady state operations is required to perform a proper inventory balance since calculations during maneuvering are **NOT** useful. For RCS operational leakage determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, Pressurizer and makeup tank levels, makeup and letdown, and Reactor Coolant Pump seal injection and return flows.

An early warning of PRESSURE BOUNDARY LEAKAGE or UNIDENTIFIED LEAKAGE is provided by the automatic systems that monitor containment atmosphere radioactivity, containment normal sump inventory and discharge, and reactor head flange leak-off. It should be noted that leakage past seals and gaskets is **NOT** PRESSURE BOUNDARY LEAKAGE. These leakage detection systems are specified in LCO 3.4.6.1, Reactor Coolant System Leakage Detection Systems.

Note ** states that this SR is **NOT** applicable to primary-to-secondary leakage because leakage of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The ~~72 hour~~ frequency is a reasonable interval to trend leakage and recognizes the importance of early leakage detection in the prevention of accidents.

d.

This SR demonstrates that the RCS Operational Leakage is within the LCO limits by monitoring the Reactor Head Flange Leak-off System ~~at least once per 24 hours~~.

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3/4.4.6.2 (Continued)

e.

This SR verifies that primary-to-secondary leakage is less than or equal to 150 gpd through any one SG. Satisfying the primary-to-secondary leakage limit ensure that the operational leakage performance criterion in the Steam Generator Program is met. If this SR is **NOT** met, compliance with LCO 3.4.5, Steam Generator (SG) Tube Integrity, should be evaluated. The 150-gpd limit is measured at room temperature as described in Reference 5. The operational leakage rate limit applies to leakage through any one SG. If it is **NOT** practical to assign the leakage to an individual SG, all the primary to secondary leakage should be conservatively assumed to be from one SG.

The SR is modified by Note ***, which states that the Surveillance is **NOT** required to be performed until 12 hours after establishment of steady state operation. For RCS primary to-secondary leakage determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and reactor coolant pump seal injection and return flows.

The surveillance frequency ~~of 72 hours~~ is a reasonable interval to trend primary to secondary leakage and recognizes the importance of early leakage detection in the prevention of accidents. The primary-to-secondary leakage is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 5).

SR 4.4.6.2.2

It is apparent that when pressure isolation is provided by two in-series check valves and when failure of one valve in the pair can go undetected for a substantial length of time, verification of valve integrity is required. Since these valves are important in preventing overpressurization and rupture of the ECCS low pressure piping, which could result in a LOCA that bypasses containment, these valves should be tested periodically to ensure low probability of gross failure.

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3/4.4.8 (Continued)

The RCS Specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

The iodine specific activity in the reactor coolant is limited to 0.25 μCi/gm DOSE EQUIVALENT I-131, and the noble gas specific activity in the reactor coolant is limited to 447.7 μCi/gm DOSE EQUIVALENT XE-133. The limits on specific activity ensure that the offsite and Control Room doses will meet the appropriate SRP acceptance criteria.

The SLB, SGTR, Locked Rotor, and RCCA Ejection Accident analyses show that the calculated doses are within limits. Violation of the LCO may result in reactor coolant activity levels that could, in the event of any one of these accidents, lead to doses that exceed the acceptance criteria.

The ACTIONS permit limited operation when DOSE EQUIVALENT I-131 is greater than 0.25 μCi/gm and less than 60 μCi/gm. The Actions require sampling within 4 hours and every 4 hours following to establish a trend.

One surveillance requires performing a gamma isotropic analysis as a measure of noble gas specific activity of the reactor coolant ~~at least once per 7 days.~~ This measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This surveillance provides an indication of any increase in the noble gas specific activity.

A second surveillance is performed to ensure that iodine specific activity remains within the LCO limit ~~once per 14 days~~ during normal operation and following fast power changes when iodine spiking is more apt to occur. The frequency between 2 and 6 hours after a power change of greater than 15% RATED THERMAL POWER within a 1 hour period, is established because the iodine levels peak during this time following iodine spike initiation.

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3/4.5.2 & 3/4.5.3 (Continued)

When PC-600/-601 are calibrated, a test signal is supplied to each circuit to check operation of the relays and annunciators operated by subject controllers. This test signal will prevent MOVs 862A, 862B, 863A, 863B from opening. Therefore, it is appropriate to tag out the MOV breakers, and enter Technical Specification Action Statement 3.5.2.a. and 3.6.2.1 when calibrating PC-600/-601.

With the RCS temperature below 350°F, operation with less than full redundant equipment is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the limited core cooling requirements.

TS 3.5.2, Action g. provides an allowed outage/action completion time (AOT) of up to 7 days to restore an inoperable RHR Pump to OPERABLE status, provided the affected ECCS Subsystem is inoperable only because its associated RHR Pump is inoperable. This 7 day AOT is based on the results of a deterministic and probabilistic safety assessment, and is referred to as a Risk-Informed AOT Extension. Planned entry into this AOT requires that a Risk Assessment be performed in accordance with the Configuration Risk Management Program (CRMP), which is described in the administrative procedure that implements the Maintenance Rule pursuant to 10CFR50.56.

TS Surveillance 4.5.2.a requires that each ECCS component and flow path be demonstrated operable ~~at least once per 12 hours~~ by verifying by Control Room indication that the valves listed in Section 4.5.2.a are in the indicated positions with power to the valve operators removed. Verifying Control Room indication applies to the valve position and **NOT** to the valve operator power removal. The breaker position may be verified by either the off condition of the breaker position indication light in the Control Room, or the verification of the locked open breaker position in the field. Verifying that power is removed to the applicable valve operators can be accomplished by direct field indication of the breaker (locked in the open position), or by observation of the breaker position status lamp in the Control Room (lamp is off when breaker is open). Surveillance Requirements for throttle valve position stops prevent total pump flow from exceeding runout conditions when the system is in its minimum resistance configuration.

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3/4.5.2 & 3/4.5.3 (Continued)

periodic

ECCS "accessible discharge piping" is defined as discharge piping outside of containment in accordance with NRC Generic Letter 2008-01, Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems interpretation. High point vents (current or added) outside of containment on the HHSI and RHR Systems discharge piping are considered accessible. These valves must be included in the ~~monthly~~ venting procedure to comply with Technical Specification Surveillance Requirement 4.5.2.b.1. This clarification was added as a corrective action to CR# 2009-18558.

In the RHR test, differential head is specified in feet. This criteria will allow for compensation of test data with water density due to varying temperature.

ECCS pump testing for the SI and RHR Pumps accounts for possible underfrequency conditions, i.e., the results of pump testing performed at 60 Hz is then adjusted to reflect possible degraded grid conditions (60±0.6) to the lower limit (59.4 Hz).

> **<u>CAUTION</u>**
>
> **Interim Compensatory Measure**
>
> TS 3.5.2 Action 'a' has been determined to be non-conservative with respect to the safety analysis as it allows up to 72 hours for restoration of the inoperable flow path despite inoperability of both ECCS trains during this period. Therefore, until appropriate changes to TS 3/4.5.2 via LAR 212 are approved and implemented, <u>TS 3.0.3 shall be entered vice TS 3.5.2 Action 'a' in the event that the suction flow path from the RWST to the ECCS is inoperable.</u> Reference AR 1811016.

Technical Specifications Surveillance Requirement 4.5.2.e.3 requires that each ECCS component and flow path be demonstrated OPERABLE ~~every 18 months~~ by visual inspection which verifies sump components (trash racks, screens, etc.) show **NO** evidence of structural distress or abnormal corrosion. The strainer modules are rigid enough to provide both functions as trash racks and screens without losing their structural integrity and particle efficiency. Therefore, strainer modules are functionally equivalent to trash racks and screens. Accordingly, the categorical description, sump components, is broad enough to require inspection of the strainer modules.

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3/4.6.2.2 (Continued)

The allowable out-of-service time requirements for the Containment Cooling System have been maintained consistent with that assigned other inoperable ESF equipment and do **NOT** reflect the additional redundancy in cooling capability provided by the Containment Spray System.

The frequency

The surveillance requirement for ECC flow ~~is~~ verified by correlating the test configuration value with the design basis assumptions for system configuration and flow. ~~An 18-month surveillance interval~~ is acceptable based on the use of water from the CCW system, which results in a low risk of heat exchanger tube fouling.

3/4.6.2.3 Recirculation pH Control System

The Recirculation pH Control System is a passive safeguard consisting of 10 stainless steel wire mesh baskets (2 large and 8 small) containing sodium tetra borate decahydrate (NaTB) located in the containment basement (14' elevation). The initial containment spray will be boric acid solution from the Refueling Water Storage Tank. The recirculation pH control system adds NaTB to the Containment Sump when the level of boric acid solution from the Containment Spray and the coolant lost from the Reactor Coolant System rises above the bottom of the buffering agent baskets. As the sump level rises, the NaTB will begin to dissolve. The addition of NaTB from the buffering agent baskets ensures the containment sump pH will be greater than 7.0. The resultant alkaline pH of the spray enhances the ability of the recirculated spray to scavenge fission products from the containment atmosphere. The alkaline pH in the recirculation sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on stainless steel piping systems exposed to the solution.

The OPERABILITY of the recirculation pH control system ensures that there is sufficient NaTB available in the containment to ensure a sump pH greater than 7.0 during the recirculation phase of a postulated LOCA. The baskets will **NOT** interact with surrounding equipment during a seismic event.

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3/4.6.2.3 (Continued)

To satisfy the surveillance requirement, the two large baskets and eight small baskets must contain a combined mass greater than 7500 lbm of NaTB. As shown in the above table, this will ensure the sump pH exceeds 7.0 at the onset of spray recirculation and for the duration of the analyzed 30-day period. The large baskets have a length and width of 54 inches, and a height of 33.25 inches and are elevated 3.5 inches above the containment floor. The smaller baskets have a length and width of 36 inches and a height of 30 inches and are elevated 4.5 inches above the containment floor. Varying basket dimensions or elevation (e.g. basket leg height) impacts the surface to volume ratio and changes the time the NaTB is in contact with containment sump water. For instance, shorter legs would allow the NaTB to contact containment sump water sooner, therefore increasing the pH at the onset of recirculation. Longer legs, however, would reduce the pH at the onset of recirculation. The level of NaTB in the baskets required to provide an equilibrium sump solution pH greater than 7.0 is 14.75 inches from the top of the basket; 18.50 inches for the large baskets and 15.25 inches for the small baskets from the bottom of the basket. The ~~18 month~~ frequency for Surveillance Requirement 4.6.2.3 is sufficient to ensure that the stainless steel buffering agent baskets are intact and contain the required quantity of NaTB.

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3/4.7.1.2 Auxiliary Feedwater System

The OPERABILITY of the Auxiliary Feedwater System ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total Loss-Of-Offsite Power. Steam can be supplied to the pump turbines from either or both units through redundant steam headers. Two D.C. motor operated valves and one A.C. motor operated valve on each unit isolate the three main steam lines from these headers. Both the D.C. and A.C. motor operated valves are powered from safety-related sources. Auxiliary feedwater can be supplied through redundant lines to the safety-related portions of the main feedwater lines to each of the steam generators. Air operated fail closed flow control valves are provided to modulate the flow to each steam generator. Each Steam Driven Auxiliary Feedwater Pump has sufficient capacity for single and two unit operation to ensure that adequate feedwater flow is available to remove decay heat and reduce the Reactor Coolant System temperature to less than 350°F when the Residual Heat Removal System may be placed into operation.

ACTION statement 2 describes the actions to be taken when both Auxiliary Feedwater Trains are inoperable. The requirement to verify the availability of both Standby Feedwater Pumps is to be accomplished by verifying that both pumps have successfully passed their periodic ~~monthly~~ surveillance tests within the last surveillance interval. The requirement to complete this action before beginning a unit shutdown is to ensure that an alternate feedwater train is available before putting the affected unit through a transient. If **NO** alternate feedwater trains are available, the affected unit is to stay at the same condition until an auxiliary feedwater train is returned to service, and then invoke ACTION statement 1 for the other train. If both Standby Feedwater Pumps are made available before one Auxiliary Feedwater Train is returned to an OPERABLE status, then the affected units shall be placed in at least HOT STANDBY within 6 hours and HOT SHUTDOWN within the following 6 hours.

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3/4.7.1.2 (Continued)

ACTION statement 3 describes the actions to be taken when a single Auxiliary Feedwater Pump is inoperable. The requirement to verify that two independent Auxiliary Feedwater Trains are OPERABLE is to be accomplished by verifying that the requirements for Table 3.7-3 have been successfully met for each train within the last surveillance interval. The provisions of Specification 3.0.4 are **NOT** applicable to the third auxiliary feedwater pump provided it has **NOT** been inoperable for longer than 30 days. This means that a units can change OPERATIONAL MODES during a unit's heatup with a single Auxiliary Feedwater Pump inoperable as long as the requirements of ACTION Statement 3 are satisfied.

The specified flow rate acceptance criteria conservatively bounds the limiting AFW flow rate modeled in the single unit Loss Of Normal Feedwater analysis. Dual unit events such as a two unit Loss Of Offsite Power require a higher pump flow rate, but it is **NOT** practical to test both units simultaneously. The ~~monthly~~ flow surveillance test specified in 4.7.1.2.1.1 is considered to be a general performance test for the AFW system and does **NOT** represent the limiting flow requirement for AFW. Check valves in the AFW system that require full stroke testing under limiting flow conditions are tested under Technical Specification 4.0.5.

The ~~monthly~~ testing of the Auxiliary Feedwater Pumps will verify their OPERABILITY. Proper functioning of the turbine admission valve and the operation of the pumps will demonstrate the integrity of the system. Verification of correct operation will be made both from instrumentation within the Control Room and direct visual observation of the pumps.

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3/4.7.1.6 (Continued)

The Standby Steam Generator Feedwater Pumps are **NOT** designed to NRC requirements applicable to Auxiliary Feedwater Systems and **NOT** required to satisfy Design Basis Events requirements. These pumps may be out of service for up to 24 hours before initiating formal notification because of the extremely low probability of a demand for their operation.

The guidelines for NRC notification in case of both pumps being out of service for longer than 24 hours are provided in applicable plant procedures, as a voluntary 4 hour notification.

Adequate demineralized water for the Standby Steam Generator Feedwater system will be verified ~~once per 24 hours~~ periodically. The Demineralized Water Storage Tank provides a source of water to several systems and therefore, requires daily verification.

The Standby Steam Generator Feedwater Pumps will be verified OPERABLE ~~monthly~~ on a STAGGERED TEST BASIS by starting and operating them in the recirculation mode. Also, during each unit's refueling outage, each Standby Steam Generator Feedwater Pump will be started and aligned to provide flow to the nuclear unit's steam generators.

This surveillance regimen will thus demonstrate operability of the entire flow path, backup non-safety grade power supply and pump associated with a unit at least each refueling outage. The pump, motor driver, and normal power supply availability would typically be demonstrated by operation of the pumps in the recirculation mode monthly on a staggered test basis.

The diesel engine driver for the B Standby Steam Generator Feedwater Pump will be verified operable ~~once every 31 days~~ periodically on a staggered test basis performed ~~on the B Standby Steam Generator Feedwater Pump~~. In addition, an inspection will be performed on the diesel ~~at least once every 18 months~~ periodically in accordance with procedures prepared in conjunction with its manufacture's recommendations for the diesel's class of service. This inspection will ensure that the diesel driver is maintained in good operating condition consistent with FPLs overall objectives for system reliability.

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3/4.7.1.7 (Continued)

Inoperable FCVs and FIVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable in view of valve status indications available in the Control Room, and other administrative controls, to ensure that these valves are closed or isolated.

With two valves in the same flow path inoperable, there may be **NO** redundant system to operate automatically and perform the required safety function. Although the Containment can be isolated with the failure of two valves in parallel in the same flow path, the double failure can be an indication of a common mode failure in the valves of this flow path, and as such, is treated the same as a loss of the isolation capability of this flow path. Under these conditions, affected valves in each flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the FCV or FIV, or otherwise isolate the affected flow path.

SR 4.7.1.7.a verifies that each FCV, FIV, and bypass line valve will actuate to its isolation position on an actuation or simulated actuation signal. The ~~18 month~~ Frequency is based on a refueling cycle interval and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the frequency was concluded to be acceptable from a reliability standpoint.

SR 4.7.1.7.b verifies that the closure time of each FCV, FIV, and bypass line valve, when tested in accordance with the Inservice Testing Program, is within the limits assumed in the accident and containment analyses. This SR is normally performed upon returning the unit to operation following a refueling outage. These valves should **NOT** be tested at power, since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME Code Section XI (Ref. 3), quarterly stroke requirements during operation in MODES 1 and 2.

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

A thermographic examination of high-risk potential ignition sources in the Cable Spreading Room and the Control Room,

Restriction of planned hot work in the Cable Spreading Room and Control Room during the extended AOT, and

Establishment of a continuous fire watch in the Cable Spreading Room when in the extended AOT.

In addition to the predetermined restrictions, assessments performed in accordance with the provisions of the Maintenance Rule (a)(4) will ensure that any other risk significant configurations are identified before removing an EDG from service for pre-planned maintenance.

A configuration risk management program has been established at Turkey Point 3 and 4 via the implementation of the Maintenance Rule and the On line Risk Monitor to ensure the risk impact of out of service equipment is appropriately evaluated prior to performing any maintenance activity.

The Surveillance Requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guides 1.9, Selection of Diesel Generator Set Capacity for Standby Power Supplies, March 10, 1971; 1.108, Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants, Revision 1, August 1977; and 1.137, Fuel-oil Systems for Standby Diesel Generators, Revision 1, October 1979.

The EDG Surveillance testing requires that each EDG be started from normal conditions ~~only once per 184 days~~ with **NO** additional warmup procedures.

Normal conditions in this instance are defined as the pre-start temperature and lube oil conditions each EDG normally experiences with the continuous use of prelube systems and immersion heaters.

periodically

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3/4.8.1, 3/4.8.2 & 3/4.8.3 (Continued)

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does **NOT** represent a failure to meet the Limiting Condition for Operation of TS 3.8.1.1, since the new fuel oil has **NOT** been added to the Diesel Fuel Oil Storage Tanks.

Within 30 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM-D975-81 are met when tested in accordance with ASTM-D975-81 except that the analysis for sulfur may be performed in accordance with ASTM-D1552-79 or ASTM-D2622-82. The 30 day period is acceptable because the fuel oil properties of interest, even if they are **NOT** within limits, would **NOT** have an immediate effect on EDG operation. The Diesel Fuel Oil Surveillance in accordance with the Diesel Fuel Oil Testing Program will ensure the availability of high quality diesel fuel oil for the EDGs.

Lubricity Specification for Ultra Low Sulfur Diesel Fuel Oil

To ensure that Ultra Low Sulfur Diesel fuel (15 pm sulfur, S15) is acceptable for use in the Emergency Diesel Generators, a test is added in the Diesel Fuel Oil Testing Program that validates, satisfactory lubricity (Reference: Engineering Evaluation PTN-ENG-SEMS-06-0035).

The test for lubricity is based on ASTM D975-06, testing per ASTM D6079, using the High Frequency Reciprocating Rig (HFRR) test at 60 degrees C and the acceptance criterion requires a wear scar **NO** larger than 520 microns.

Periodically,

~~At least once every 31 days,~~ a sample of fuel oil is obtained from the storage tanks in accordance with ASTM-D2276-78. The particulate contamination is verified to be less than 10 mg/liter when checked in accordance with ASTM-D2276-78, Method A. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does **NOT** mean the fuel oil will **NOT** burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

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3/4.9 Refueling Operations

3/4.9.1 Boron Concentration

The limitations on reactivity conditions during REFUELING ensure that: (1) The reactor will remain subcritical during CORE ALTERATIONS, and (2) A uniform boron concentration is maintained for reactivity control in the water volume having direct access to the reactor vessel. These limitations are consistent with the initial conditions assumed for the boron dilution incident in the safety analyses. With the required valves closed during refueling operations the possibility of uncontrolled boron dilution of the filled portion of the RCS is precluded. This action prevents flow to the RCS of unborated water by closing flow paths from sources of unborated water. The boration rate requirement of 16 gpm of 3.0 wt% (5245 ppm) boron or equivalent ensures the capability to restore the SHUTDOWN MARGIN with one OPERABLE charging pump.

The OPERABILITY of the Source Range Neutron Flux Monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. There are four source range neutron flux channels, two primary, and two backup. All four channels have visual and alarm indication in the Control Room and interface with the containment evacuation alarm system. The primary source range neutron flux channels can also generate reactor trip signals and provide audible indication of the count rate in the Control Room and containment. At least one primary source range neutron flux channel to provide the required audible indication, in addition to its other functions, and one of the three remaining source range channels shall be OPERABLE to satisfy the LCO.

3/4.9.2 Instrumentation

T.S. surveillance requirement 4.9.2.b and c states:

Each required Source Range Neutron Flux Monitor shall be demonstrated OPERABLE by performance of:

b. An ANALOG CHANNEL OPERATIONAL TEST within 8 hours prior to the initial start of CORE ALTERATIONS, and

c. An ANALOG CHANNEL OPERATIONAL TEST ~~at least once per 7 days.~~ periodically.

# Attachment 5

# Turkey Point Nuclear Plant

# License Amendment Request No. LAR-229

## No Significant Hazards Consideration Determination

# No Significant Hazards Consideration

## Description of Amendment Request:

The change requests the adoption of an approved change to the Standard Technical Specifications (STS) for Westinghouse Plants (NUREG-1431) to allow relocation of specific TS surveillance frequencies to a licensee-controlled program. The proposed change is described in Technical Specification Task Force (TSTF) Traveler, TSTF-425, Revision 3 (ADAMS Accession No. ML090800642) related to the Relocation of Surveillance Frequencies to Licensee Control – RITSTF Initiative 5b and was described in the Notice of Availability published in the *Federal Register* on July 6, 2009 (74 FR 31966).

The proposed changes are consistent with NRC-approved industry/ TSTF Traveler TSTF-425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control – RITSTF Initiative 5b." The proposed change relocates surveillance frequencies to a licensee-controlled program, the Surveillance Frequency Control Program. This change is applicable to licensees using probabilistic risk guidelines contained in NRC approved Nuclear Energy Institute (NEI) 04-10, "Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies," (ADAMS Accession No. ML071360456).

Surveillance frequencies that have a set periodicity will be relocated to the Surveillance Frequency Control Program controlled by the licensee. Accordingly, changes to the periodicity can be made without prior NRC approval, provided they are made within the constraints of the Program. These constraints include, but are not limited to an engineering evaluation, an assessment of the risk associated with the change, and a review by an independent decision-making panel.

## Basis for proposed no significant hazards consideration:

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

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

   Response: No

   The proposed change relocates the specified frequencies for periodic surveillance requirements to licensee control under a new Surveillance Frequency Control Program. Surveillance frequencies are not an initiator to any accident previously evaluated. As a result, the probability of any accident previously evaluated is not significantly increased. The systems and components required by the technical specifications for which the surveillance frequencies are relocated are still required to be operable, meet the acceptance criteria for the surveillance requirements, and be capable of performing any mitigation function assumed in the accident analysis. As a result, the consequences of any accident previously evaluated are not significantly increased.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No

   The proposed changes relocate the surveillance frequencies for Surveillance Requirements that have a set periodicity from the TS to a licensee controlled Surveillance Frequency Control Program. This change does not alter any existing surveillance frequencies. Within the constraints of the Program, the licensee will be able to change the periodicity of these surveillance requirements. Relocating the surveillance frequencies does not impact the ability of structures, systems or components (SSCs) from performing there design functions, and thus, does not create the possibility of a new or different kind of accident from any previously evaluated.

   No new or different accidents result from utilizing the proposed change. The changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed) or a change in the methods governing normal plant operation. In addition, the changes do not impose any new or different requirements. The changes do not alter assumptions made in the safety analysis assumptions and current plant operating practice.

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

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

   Response: No

   The design, operation, testing methods, and acceptance criteria for systems, structures, and components (SSCs), specified in applicable codes and standards (or alternatives approved for use by the NRC) will continue to be met as described in the plant licensing basis (including the final safety analysis report and bases to TS), since these are not affected by changes to the surveillance frequencies. Similarly, there is no impact to safety analysis acceptance criteria as described in the plant licensing basis. To evaluate a change in the relocated surveillance frequency, FPL will perform a probabilistic risk evaluation using the guidance contained in NRC-approved NEI 04-10, Revision 1 in accordance with the TS Surveillance Frequency Control Program. NEI 04-10, Revision 1, methodology provides reasonable acceptance guidelines and methods for evaluating the risk increase of proposed changes to surveillance frequencies consistent with Regulatory Guide (RG) 1.177, An Approach for Plant-Specific Risk-Informed Decision-Making: Technical Specifications.

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

Based upon the discussion above, FPL concludes that the requested change does not involve a significant hazards consideration as set forth in 10 CFR 50.92(c), Issuance of Amendment.

# Attachment 6

## Turkey Point Nuclear Plant
## License Amendment Request No. LAR-229

## Cross-Reference Between TSTF-425 and Turkey Point Technical Specifications

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| **3.1 Reactivity Control Systems** | | |
| **3.1.1, Shutdown Margin (SDM)** | | |
| Verify SDM to be within limits specified in the COLR. | SR 3.1.1.1 | ----- |
| *When in MODES 1 or 2 with keff ≥1 ... control bank withdrawal is within limits of specification 3.1.3.6.* | ----- | 4.1.1.1.1.b |
| *When in MODES 3 or 4, ...consideration of the following factors:* | ----- | 4.1.1.1.1.e |
| *SDM hall be determined to be within limit ... by consideration of the following factors:* | ----- | 4.1.1.2.b |
| **3.1.2, Core Reactivity** | | |
| Verify measured core reactivity is within ±1% Δk/k of predicted values. | SR 3.1.2.1 | 4.1.1.1.2 |
| **3.1.4, Rod Group Alignment Limits** | | |
| Verify individual rod positions within alignment limit. | SR 3.1.4.1 | 4.1.3.1.1 |
| Verify rod freedom of movement by moving each rod not fully inserted in the core ≥10 steps in either direction. | SR 3.1.4.2 | 4.1.3.1.2 |
| *Verify demand position indicating system and analog position indicating system agree within allowable deviation.* | ----- | 4.1.3.2.1 |
| *Perform channel check, channel calibration and analog channel operational test – individual rod position.* | ----- | 4.1.3.2.2<br>Table 4.1-1 |
| *Channel check and analog channel operational test – demand position.* | ----- | 4.1.3.2.2<br>Table 4.1-1 |
| *Verify group demand position indicator operable by movement of associated control rod.* | ----- | 4.1.3.3.1 |
| *Verify rod drop time of full length rods* | ----- | 4.1.3.4.c |
| **3.1.5, Shutdown Bank Insertion Limits** | | |
| Verify each shutdown bank is within the insertion limit specified in the COLR. | SR 3.1.5.1 | 4.1.3.5.b |
| **3.1.6, Control Bank Rod Insertion Limits** | | |
| Verify each control bank position is within the limits specified in the COLR | SR 3.1.6.2 | 4.1.3.6 |
| Verify sequence and overlap limits specified in the COLR are met for control banks not fully withdrawn from the core. | SR 3.1.6.3 | ----- |
| **3.1.8, Physics Test Exceptions – MODE 2** | | |
| Verify RCS lowest loop temperature ≥[531]°F. | SR 3.1.8.2 | 4.10.3.3 |
| Verify thermal power is ≤ 5% RTP . | SR 3.1.8.3 | 4.10.3.1 |
| Verify SDM within limits specified in the COLR. | SR 3.1.8.4 | 4.10.1.1 |
| ***TURKEY POINT TECHNICAL SPECIFICATIONS*** | | |
| ***3/4.1.2, Boration System – Flowpath - Shutdown*** | | |
| *Verify each valve in the flow path that is not locked, sealed, or otherwise secured in position is in correct position.* | ----- | 4.1.2.1.b |

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| ***3/4.1.2, Boration System – Flowpath - Operating*** | | |
| *Verify each valve in the flow path that is not locked, sealed, or otherwise secured in position is in correct position.* | ----- | 4.1.2.2.b |
| *Verify the flowpath … delivers at least 16 gpm to the RCS.* | ----- | 4.1.2.2.c |
| ***3/4.1.2, Boration System – Borated Water Sources - Shutdown*** | | |
| *Verify boron concentration.* | ----- | 4.1.2.4.a.1 |
| *Verify indicated borated water volume.* | ----- | 4.1.2.4.a.2 |
| *Verify temperature of boric acid tanks room ≥62°F, when it is source of borated water* | ----- | 4.1.2.4.a.3 |
| ***3/4.1.2, Boration System – Borated Water Sources - Operating*** | | |
| *Verify boron concentration.* | ----- | 4.1.2.5.a.1 |
| *Verify indicated borated water volume.* | ----- | 4.1.2.5.a.2 |
| *Verify temperature of boric acid tanks room ≥62°F, when it is source of borated water* | ----- | 4.1.2.5.a.3 |
| **3.2 Power Distribution Limits** | | |
| **3.2.1, Heat Flux Hot Channel Factor** | | |
| Verify $F^C_Q(Z)$ are within limits | SR 3.2.1.1 | 4.2.2.1.d.2 |
| *Determine $F_J(Z)$ using Moveable Incore Detectors* | ----- | 4.2.2.2.b.1 |
| *Update flux map* | ----- | 4.2.2.2.c.3 |
| **3.2.2, Nuclear Enthalpy Rise Hot Channel Factor** | | |
| Verify $F^N_{\Delta H}$ is within limits | SR 3.2.2.1 | 4.2.3.3.b |
| **3.2.3, Axial Flux Difference** | | |
| Verify AFD within limits | SR 3.2.3.1 | 4.2.1.1.a.1 |
| *Determine target flux difference* | ----- | 4.2.1.2 |
| *Update target flux difference* | ----- | 4.2.1.3 |
| **3.2.4, Quadrant Power Tilt Ratio** | | |
| Verify QPTR within limits by calculation | SR 3.2.4.1 | 4.2.4.1.a |

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| **3.3 Instrumentation** | | |
| **3.3.1, Reactor Trip System Instrumentation** | | |
| Perform Channel Check | SR 3.3.1.1 | 4.3.1.1, Table 4.3-1 Functional Units – 2a, 2b, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 |
| Compare Calorimetric Heat Balance to Power Range Channel – Adjust as necessary | SR 3.3.1.2 | 4.3.1.1, Table 4.3-1 Functional Unit – 2a |
| Incore Detector validation | SR 3.3.1.3 | ----- |
| Perform Trip Actuating Device Operational Test (TADOT) | SR 3.3.1.4 | 4.3.1.1, Table 4.3-1 Functional Units – 18, 19, 21 |

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| Perform Actuation Logic Test | SR 3.3.1.5 | 4.3.1.1, Table 4.3-1 Functional Unit – 20 |
| Calibrate excore channels | SR 3.3.1.6 | 4.3.1.1, Table 4.3-1 Functional Unit – 2a ----- |
| Perform Channel Operational Test (COT) | SR 3.3.1.7 | 4.3.1.1, Table 4.3-1 Functional Units – 2a, 4, 5, 6, 7, 8, 9, 10, 11, 12 |
| Perform COT | SR 3.3.1.8 | ----- |
| Perform TADOT | SR 3.3.1.9 | ----- |
| Perform Channel Calibration | SR 3.3.1.10 | 4.3.1.1, Table 4.3-1 Functional Units – 9, 10, 11, 12, 13, 14, 15a, 15b |
| Perform Channel Calibration | SR 3.3.1.11 | 4.3.1.1, Table 4.3-1 Functional Units – 2b, 3, 4, 5, 17a, 17b, 17c, 17d |
| Perform Channel Calibration | SR 3.3.1.12 | 4.3.1.1, Table 4.3-1 Functional Units – 6, 7, 8 |
| Perform COT | SR 3.3.1.13 | 4.3.1.1, Table 4.3-1 Functional Units – 17a, 17b, 17c, 17d |
| Perform TADOT | SR 3.3.1.14 | 4.3.1.1, Table 4.3-1 Functional Units – 1, 16 |
| Perform RTS Response Time Test | SR 3.3.1.16 | ----- |
| **3.3.2, Engineered Safety Feature Actuation System Instrumentation** | | |
| Perform Channel Check | SR 3.3.2.1 | 4.3.2.1, Table 4.3-2 Functional Units – 1d, 1e, 1f, 3c4, 4d, 5c, 6b, 7b, 7c, 9c, 9e |
| Perform Actuation Logic Test | SR 3.3.2.2 | 4.3.2.1, Table 4.3-2 Functional Units – 1b, 1c, 2a, 2b, 3a2, 3b2, 3b3, 4b, 4c, 5a, 6a |
| Perform Actuation Logic Test | SR 3.3.2.3 | ----- |
| Perform Master Relay Test | SR 3.3.2.4 | 4.3.2.1, Table 4.3-2 Functional Units – 1b, 2a, 3a2, 3b2, 4b, 5a, 6a |
| Perform COT | SR 3.3.2.5 | 4.3.2.1, Table 4.3-2 Functional Units – 1d, 1e, 1f, 3c4, 4d, 5c, 6b, 8a, 8b, 9c, 9e |
| Perform Slave Relay Test | SR 3.3.2.6 | 4.3.2.1, Table 4.3-2 Functional Units – 1b, 2a, 3a2, 3b2, 4b, 5a, 6a |
| Perform TADOT | SR 3.3.2.7 | 4.3.2.1, Table 4.3-2 Functional Units – 6d, 7a, 7b, 7c |

| Surveillance Requirements | TSTF-425 Surveillance *Requirement* | Turkey Point Surveillance *Requirement* |
|---|---|---|
| Perform TADOT | SR 3.3 2.8 | 4.3.2.1, Table 4.3-2 Functional Units – 1a, 2b, 3a1, 3b1, 3b3, 3c1, 4a, 4c, 6e, 9d |
| Perform Channel Calibration | SR 3.3.2.9 | 4.3.2.1, Table 4.3-2 Functional Units – 1c, 1d, 1e, 1f, 2b, 3b3, 3c4, 4c, 4d, 5c, 6b, 6d, 7a, 7b, 7c, 8a, 8b, 9c, 9e |
| Perform ESFAS Response Time Test | SR 3.3.2.10 | ----- |
| **3.3.3, Post Accident Monitoring Instrumentation** | | |
| Perform Channel Check | SR 3.3.3.1 | 4.3.3.3, Table 4.3-4 |
| Perform Channel Calibration | SR 3.3.3.2 | 4.3.3.3, Table 4.3-4 |
| **3.3.4, Remote Shutdown System** | | |
| Perform Channel Check | SR 3.3.4.1 | ----- |
| Verify control circuit and transfer switch | SR 3.3.4.2 | ----- |
| Perform Channel Calibration | SR 3.3.4.3 | ----- |
| Perform TADOT | SR 3.3.4.4 | ----- |
| **3.3.5, Loss of Power Diesel Generator Start Instrumentation** | | |
| Perform Channel Check | SR 3.3.5.1 | ----- |
| Perform TADOT | SR 3.3.5.2 | ----- |
| Perform Channel Calibration | SR 3.3.5.3 | ----- |
| **3.3.6, Containment Purge and Exhaust Isolation Instrumentation** | | |
| Perform Channel Check | SR 3.3.6.1 | ----- |
| Perform Actuation Logic Test | SR 3.3.6.2 | ----- |
| Perform Master Relay Test | SR 3.3.6.3 | ----- |
| Perform Actuation Logic Test | SR 3.3.6.4 | ----- |
| Perform Master Relay Test | SR 3.3.6.5 | ----- |
| Perform COT | SR 3.3.6.6 | ----- |
| Perform Slave Relay Test | SR 3.3.6.7 | ----- |
| Perform TADOT | SR 3.3.6.8 | ----- |
| Perform Channel Calibration | SR 3.3.6.9 | ----- |
| **3.3.7, Control Room Emergency Filtration System Actuation Instrumentation** | | |
| Perform Channel Check | SR 3.3.7.1 | ----- |
| Perform COT | SR 3.3.7.2 | ----- |
| Perform Actuation Logic Test | SR 3.3.7.3 | ----- |
| Perform Master Relay Test | SR 3.3.7.4 | ----- |
| Perform Actuation Logic Test | SR 3.3.7.5 | ----- |
| Perform Master Relay Test | SR 3.3.7.6 | ----- |
| Perform Slave Relay Test | SR 3.3.7.7 | ----- |
| Perform TADOT | SR 3.3.7.8 | ----- |
| Perform Channel Calibration | SR 3.3.7.9 | ----- |

| **Surveillance Requirements** | **TSTF-425 Surveillance Requirement** | **Turkey Point Surveillance Requirement** |
|---|---|---|
| **3.3.8, Fuel Building Air Cleanup System Actuation Instrumentation** | | |
| Perform Channel Check | SR 3.3.8.1 | ----- |
| Perform COT | SR 3.3.8.2 | ----- |
| Perform Actuation Logic Test | SR 3.3.8.3 | ----- |
| Perform TADOT | SR 3.3.8.4 | ----- |
| Perform Channel Calibration | SR 3.3.8.5 | ----- |
| **3.3.9, Boron Dilution Protection System** | | |
| Perform Channel Check | SR 3.3.9.1 | ----- |
| Perform COT | SR 3.3.9.2 | ----- |
| Perform Channel Calibration | SR 3.3.9.3 | ----- |
| ***TURKEY POINT TECHNICAL SPECIFICATIONS*** | | |
| ***3/4.3.3, Monitoring Instrumentation*** | | |
| *Radiation Monitoring Instrumentation*<br>*Perform Channel Check* | ----- | 4.3.3.1 , Table 4.3-3 |
| *Perform Analog Channel Operational Test* | ----- | 4.3.3.1, Table 4.3-3 |
| *Perform Channel Calibration* | ----- | 4.3.3.1, Table 4.3-3 |
| *Normalize moveable incore detectors* | ----- | 4.3.3.2 |
| *Explosive Gas Monitoring Instrumentation*<br>*Perform Channel Check* | ----- | 4.3.3.6, Table 4.3-6 |
| *Perform Analog Channel Operational Test* | ----- | 4.3.3.6, Table 4.3-6 |
| *Perform Channel Calibration* | ----- | 4.3.3.6, Table 4.3-6 |

| **Surveillance Requirements** | **TSTF-425 Surveillance Requirement** | **Turkey Point Surveillance Requirement** |
|---|---|---|
| **3.4 Reactor Coolant System** | | |
| **3.4.1, RCS Pressure, Temperature, and Flow DNB Limits** | | |
| Verify pressurizer pressure ≥ limit in COLR. | SR 3.4.1.1 | 4.2.5.1 |
| Verify RCS average temperature ≥ limit in COLR. | SR 3.4.1.2 | 4.2.5.1 |
| Verify RCS total flow rate ≥ limit. | SR 3.4.1.3 | 4.2.5.2 |
| Verify RCS flow using precision heat balance | SR 3.4.1.4 | 4.2.5.4 |
| *Perform Channel Calibration – RCS flow indicators* | ----- | 4.2.5.3 |
| **3.4.2, RCS Minimum Temperature for Criticality** | | |
| Verify RCS $T_{avg}$ | SR 3.4.2.1 | ----- |
| **3.4.3, RCS Pressure and Temperature (P/T) Limits** | | |
| Verify pressure temperature and heatup and cooldown rates | SR 3.4.3.1 | ----- |
| **3.4.4, RCS Loops – MODES 1 and 2** | | |
| Verify RCS loops in operation | SR 3.4.4.1 | 4.4.1.1 |
| **3.4.5, RCS Loops – MODE 3** | | |
| Verify RCS loops in operation | SR 3.4.5.1 | 4.4.1.2.3 |
| Verify steam generator secondary side water level | SR 3.4.5.2 | 4.4.1.2.2 |
| Verify correct breaker alignment and power available | SR 3.4.5.3 | 4.4.1.2.1 |

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| **3.4.6, RCS Loops – MODE 4** | | |
| Verify RHR or RCS loop in operation | SR 3.4.6.1 | 4.4.1.3.3 |
| Verify steam generator secondary side water level | SR 3.4.6.2 | 4.4.1.3.2 |
| Verify correct breaker alignment and power available | SR 3.4.6.3 | 4.4.1.3.1 |
| **3.4.7, RCS Loops – MODE 5 – Loops Filled** | | |
| Verify RHR or RCS loop in operation | SR 3.4.7.1 | 4.4.1.4.1.2 |
| Verify steam generator secondary side water level | SR 3.4.7.2 | 4.4.1.4.1.1 |
| Verify correct breaker alignment and power available | SR 3.4.7.3 | ----- |
| **3.4.8, RCS Loops – MODE 5 – Loops Not Filled** | | |
| Verify RHR loop in operation | SR 3.4.8.1 | 4.4.1.4.2 |
| Verify correct breaker alignment and power available | SR 3.4.8.2 | ----- |
| **3.4.9, Pressurizer** | | |
| Verify water level ≤ [92]% | SR 3.4.9.1 | 4.4.3.1 |
| Verify heater capacity | SR 3.4.9.2 | 4.4.3.2 |
| Verify heater emergency power supply | SR 3.4.9.3 | ----- |
| **3.4.11, Pressurizer Power Operated Relief Valves (PORVs)** | | |
| Cycle PORV block valves | SR 3.4.11.1 | 4.4.4 |
| Cycle PORVs | SR 3.4.11.2 | ----- |
| Cycle solenoid air control and check valves | SR 3.4.11.3 | ----- |
| Verify PORV and block valve emergency power supply | SR 3.4.11.4 | ----- |
| **3.4.12, Low Temperature Overpressure Protection (LTOP) System** | | |
| Verify maximum of one HPSI pump injecting to RCS | SR 3.4.12.1 | 4.4.9.3.3 |
| Verify maximum of one charging pump injecting to RCS | SR 3.4.12.2 | 4.4.9.3.3 |
| Verify ECCS accumulators isolated | SR 3.4.12.3 | 4.4.9.3.3 |
| Verify RHR suction valves open | SR 3.4.12.4 | ----- |
| Verify RCS vent open | SR 3.4.12.5 | 4.4.9.3.2 |
| Verify PORV block valve open | SR 3.4.12.6 | 4.4.9.3.1.c |
| Verify RHR suction isolation valve locked open with power removed | SR 3.4.12.7 | ----- |
| Channel Operational Test - PORV | SR 3.4.12.8 | 4.4.9.3.1.a |
| Channel Calibration - PORV | SR 3.4.12.9 | 4.4.9.3.1.b |
| *Verify backup nitrogen supply* | ----- | 4.4.9.3.1.d |
| **3.4.13, RCS Operational Leakage** | | |
| Perform water inventory balance | SR 3.4.13.1 | 4.4.6.2.1.c |
| Verify primary to secondary leakage | SR 3.4.13.2 | 4.4.6.2.1.e |
| *Monitor containment atmosphere* | ----- | 4.4.6.2.1.a |
| *Monitor containment sump level* | ----- | 4.4.6.2.1.b |
| *Monitor reactor head flange leakoff system* | ----- | 4.4.6.2.1.d |
| **3.4.14, RCS Pressure Isolation Valve (PIV) Leakage** | | |
| Verify PIV leakage | SR 3.4.14.1 | 4.4.6.2.2.a |
| Verify RHR autoclosure interlock prevents valves from opening | SR 3.4.14.2 | ----- |
| Verify RHR autoclosure interlock closes valves | SR 3.4.14.3 | ----- |

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| **3.4.15, RCS Leakage Detection Instrumentation** | | |
| Perform Channel Check – containment atmosphere radioactivity monitor | SR 3.4.15.1 | 4.4.6.1, Table 4.3-3 |
| Perform Channel Operational Test – containment atmosphere radioactivity monitor | SR 3.4.15.2 | |
| Perform Channel Calibration – containment sump monitor | SR 3.4.15.3 | 4.4.6.1.b |
| Perform Channel Calibration – containment atmosphere radioactivity monitor | SR 3.4.15.4 | 4.4.6.1, Table 4.3-3 |
| Perform Channel Operational Test – containment air cooler condensate flow rate monitor | SR 3.4.15.5 | ----- |
| **3.4.16, RCS Specific Activity** | | |
| Determine gross specific activity | SR 3.4.16.1 | 4.4.8 , Table 4.4-4 |
| Determine Dose Equivalent I-131 | SR 3.4.16.2 | 4.4.8, Table 4.4-4 |
| Determine E-Bar | SR 3.4.16.3 | ----- |
| Tritium determination | ----- | 4.4.8, Table 4.4-4 |
| Determine Dose Equivalent XE-133 | ----- | 4.4.8, Table 4.4-4 |
| **3.4.17, RCS Loop Isolation Valves** | | |
| Verify valves open | SR 3.4.17.1 | ----- |
| **3.4.19, RCS Loops – Test Exceptions** | | |
| Verify Thermal Power ≥ P-7 | SR 3.4.19.1 | ----- |
| ***TURKEY POINT TECHNICAL SPECIFICATIONS*** | | |
| ***3/4.4.7, Chemistry*** | | |
| *Dissolved oxygen, Chloride, Fluoride* | ----- | 4.4.7 , Table 4.4-3 |
| ***3/4.4.9.2, RCS Vents*** | | |
| *Verify vent path* | ----- | 4.4.11 |
| **3.5 Emergency Core Cooling Systems (ECCS)** | | |
| **3.5.1, Accumulators** | | |
| Verify isolation valve open | SR 3.5.1.1 | 4.5.1.1.a.3 |
| Verify water volume | SR 3.5.1.2 | 4.5.1.1.a.1 |
| Verify nitrogen cover pressure | SR 3.5.1.3 | 4.5.1.1.a.2 |
| Verify boron concentration | SR 3.5.1.4 | 4.5.1.1.b |
| Verify power removed from isolation valve operator | SR 3.5.1.5 | 4.5.1.1.c |
| *Check valve operability* | ----- | 4.5.1.1.d |
| **3.5.2, ECCS – Operating** | | |
| Verify valve positions with power removed | SR 3.5.2.1 | 4.5.2.a |
| Verify flow path valve positions | SR 3.5.2.2 | 4.5.2.b.2 |
| Verify piping full of water | SR 3.5.2.3 | 4.5.2.b.1 |
| Verify valve automatic actuations | SR 3.5.2.5 | 4.5.2.f.1 |
| Verify automatic pump starts | SR 3.5.2.6 | 4.5.2.f.2.a<br>4.5.2.f.2.b |
| Verify throttle valve positions | SR 3.5.2.7 | 4.5.2.g.2 |
| Inspect containment sump suction inlets | SR 3.5.2.8 | 4.5.2.e.3 |
| *RHR Pump IST* | ----- | 4.5.2.b.3 |

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| *SI Pump IST* | ----- | 4.5.2.c.1 |
| *RHR automatic closure interlock* | ----- | 4.5.2.e.1 |
| *RWST isolation from RHR interlock* | ----- | 3.5.2.e.2 |
| **3.5.4, Refueling Water Storage Tank (RWST)** | | |
| Verify water temperature | SR 3.5.4.1 | ----- |
| Verify water volume | SR 3.5.4.2 | 4.5.4.a.1 |
| Verify boron concentration | SR 3.5.4.3 | 4.5.4.a.2 |
| **3.5.5, Seal Injection Flow** | | |
| Verify throttle valve position | SR 3.5.5.1 | ----- |
| **3.5.6, Boron Injection Tank** | | |
| Verify water temperature | SR 3.5.6.1 | ----- |
| Verify water volume | SR 3.5.6.2 | ----- |
| Verify boron concentration | SR 3.5.6.3 | ----- |
| **3.6 Containment Systems** | | |
| **3.6.2, Containment Air Locks** | | |
| Verify only one door can be opened | SR 3.6.2.2 | 4.6.1.3.c |
| **3.6.3, Containment Isolation Valves** | | |
| Verily [42] inch purge valves closed | SR 3.6.3.1 | 4.6.1.7.1 |
| Verily [8] inch purge valves closed | SR 3.6.3.2 | ----- |
| Verify manual isolation valves and blind flanges position | SR 3.6.3.3 | 4.6.1.1.a |
| Verify automatic valve isolation time | SR 3.6.3.5 | ----- |
| Cycle check valves | SR 3.6.3.6 | ----- |
| Perform leakage test on purge valves | SR 3.6.3.7 | 4.6.1.7.2 |
| Verify automatic valve actuations | SR 3.6.3.8 | 4.6.4.2.a<br>4.6.4.2.b<br>4.3.4.2.c |
| Cycle check valves | SR 3.6.3.9 | ----- |
| Verify purge valve opening restricted | SR 3.6.3.10 | 4.6.1.7.3 |
| Verify leakage thru shield building bypass paths | SR 3.6.3.11 | ----- |
| **3.6.4, Containment Pressure** | | |
| Verify pressure | SR 3.6.4.1 | 4.6.1.4 |
| **3.6.5, Containment Air Pressure** | | |
| Verify average air temperature | SR 3.6.5.1 | 4.6.1.5 |
| **3.6.6, Containment Spray and Cooling Systems** | | |
| Verify valve positions | SR 3.6.6.1 | 4.6.2.1.a |
| Operate cooling train fans | SR 3.6.6.2 | 4.6.2.2.a |
| Verify cooling train cooling water flow | SR 3.6.6.3 | 4.6.2.2.b.2 |
| Verify automatic valves actuate | SR 3.6.6.5 | 4.6.2.1.c.1 |
| Verify automatic containment spray pump starts | SR 3.6.6.6 | 4.6.2.1.c.2 |
| Verify automatic cooling train start | SR 3.6.6.7 | 4.6.2.2.b.1 |
| Verify spray nozzle unobstructed | SR 3.6.6.8 | 4.6.2.1.d |
| **3.6.7, Spray Additive System** | | |
| Verify valve positions | SR 3.6.7.1 | ----- |

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| Verify tank volume | SR 3.6.7.2 | ----- |
| Verify NaOH concentration | SR 3.6.7.3 | ----- |
| Verify automatic valves actuate | SR 3.6.7.4 | ----- |
| Verify spray additive flow rate | SR 3.6.7.5 | ----- |
| **3.6.9, Hydrogen Mixing System** | | |
| Operate train | SR 3.6.9.1 | ----- |
| Verify train flow rate | SR 3.6.9.2 | ----- |
| Verify automatic train start | SR 3.6.9.3 | ----- |
| **3.6.11, Iodine Cleanup System** | | |
| Operate train | SR 3.6.11.1 | ----- |
| Verify automatic train start | SR 3.6.11.3 | ----- |
| Verify bypass damper can be opened | SR 3.6.11.4 | ----- |
| ***TURKEY POINT TECHNICAL SPECIFICATIONS*** | | |
| ***3/4.6.2.3, Recirculation pH Control System*** | | |
| *Buffering agent baskets in place* | ----- | 4.6.2.3.a.1 |
| *Buffering agent quantity* | ----- | 4.6.2.3.a.2 |
| **3.7 Plant Systems** | | |
| **3.7.2, Main Steam Isolation Valves** | | |
| Verify automatic valve actuation | SR 3.7.2.2 | |
| **3.7.3, Main Feedwater Isolation Valves (MFIVs) and Main Feedwater Regulation Valves (MFRVs)** | | |
| Verify automatic valve actuation | SR 3.7.3.2 | 4.7.1.7.a.1 |
| **3.7.4, Atmospheric Dump Valves (ADVs)** | | |
| Cycle ADVs | SR 3.7.4.1 | |
| Cycle ADV block valves | SR 3.7.4.2 | |
| **3.7.5, Auxiliary Feedwater (AFW) System** | | |
| Verify valve positions | SR 3.7.5.1 | 4.7.1.2.1.a.3 |
| Verify automatic valve actuations | SR 3.7.5.3 | 4.7.1.2.1.b.1 |
| Verify automatic pump starts | SR 3.7.5.4 | 4.7.1.2.1.b.2 |
| *Operate steam-driven pump* | ----- | 4.7.1.2.1.a.1 |
| *Verify steam-driven pump valve positions* | ----- | 4.7.1.2.1.a.2 |
| *Verify power available* | ----- | 4.7.1.2.1.a.4 |
| **3.7.6, Condensate Storage Tank (CST)** | | |
| Verify tank level | SR 3.7.6.1 | 4.7.1.3 |
| **3.7.7, Component Cooling Water (CCW) System** | | |
| Verify valve positions | SR 3.7.7.1 | 4.7.2.b |
| Verify automatic valve actuations | SR 3.7.7.2 | 4.7.2.c.1 |
| Verify automatic pump starts | SR 3.7.7.3 | 4.7.2.c.2 |
| *Verify capability to remove heat* | ----- | 4.7.2.a |
| *Verify CCW interlocks* | ----- | 4.7.2.c.3 |
| **3.7.8, Service Water System (SWS)** | | |
| Verify valve positions | SR 3.7.8.1 | 4.7.3.a |
| Verify automatic valve actuations | SR 3.7.8.2 | 4.7.3.b.1 |

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| Verify automatic pump starts | SR 3.7.8.3 | 4.7.3.b.2 |
| *Verify SSW interlocks* | ----- | 4.7.3.b.3 |
| **3.7.9, Ultimate Heat Sink (UHS)** | | |
| Verify water level | SR 3.7.9.1 | ----- |
| Verify water temperature | SR 3.7.9.2 | 4.7.4 |
| Operate cooling tower fans | SR 3.7.9.3 | ----- |
| Verify automatic fan starts | SR 3.7.9.4 | ----- |
| **3.7.10, Control Room Emergency Filtration System (CREFS)** | | |
| Operate trains | SR 3.7.10.1 | 4.7.5.b |
| Verify automatic train actuations | SR 3.7.10.3 | 4.7.5.e |
| *Filter/Charcoal testing* | ----- | 4.7.5.c |
| *Pressure drop across HEPAs* | ----- | 4.7.5.d.1 |
| *Maintain negative pressure* | ----- | 4.7.5.d.2 |
| *Verify kitchen and toilet dampers* | ----- | 4.7.5.f |
| **3.7.11, Control Room Emergency Air Temperature Control System (CREATCS)** | | |
| Verify capability to remove heat | SR 3.7.11.1 | 4.7.5.a |
| **3.7.12, ECCS Pump Room Exhaust Air Cleanup System (PREACS)** | | |
| Operate trains | SR 3.7.12.1 | ----- |
| Verify automatic train actuations | SR 3.7.12.3 | ----- |
| Verify train can maintain negative pressure | SR 3.7.12.4 | ----- |
| Verify filter bypass can be closed | SR 3.7.12.5 | ----- |
| **3.7.13, Fuel Building Air Cleanup System (FBACS)** | | |
| Operate trains | SR 3.7.13.1 | ----- |
| Verify automatic train actuations | SR 3.7.13.3 | ----- |
| Verify train can maintain negative pressure | SR 3.7.13.4 | ----- |
| Verify filter bypass can be closed | SR 3.7.13.5 | ----- |
| **3.7.12, Penetration Room Exhaust Air Cleanup System (PREACS)** | | |
| Operate trains | SR 3.7.14.1 | ----- |
| Verify automatic train actuations | SR 3.7.14.3 | ----- |
| Verify train can maintain negative pressure | SR 3.7.14.4 | ----- |
| Verify filter bypass can be closed | SR 3.7.14.5 | ----- |
| **3.7.15, Fuel Storage Pool Water Level** | | |
| Verify pool water level | SR 3.7.15.1 | 4.9.11 |
| **3.7.16, Fuel Storage Pool Concentration** | | |
| Verify pool water boron concentration | SR 3.7.16.1 | 4.9.14.1 |
| **37.18, Secondary Specific Activity** | | |
| Dose Equivalent I-131 | SR 3.7.18.1 | ----- |
| *Gross activity determination* | ----- | 4.7.1.4<br>Table 4.7-1 |
| ***TURKEY POINT TECHNICAL SPECIFICATIONS*** | | |
| ***3/4.7.1.6, Standby Feedwater System*** | | |
| *Demineralized water tank volume* | ----- | 4.7.1.6.1 |

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| *Operate pumps* | ----- | 4.7.1.6.2 |
| *Feed steam generators with pumps* | ----- | 4.7.1.6.3 |
| *Operate diesel driven pump* | ----- | 4.7.1.6.4.a |
| *Diesel inspection* | ----- | 4.7.1.6.4.b |
| ***3/4.7.7, Sealed Source Contamination*** | | |
| *Test sources in use* | ----- | 4.7.7.2.a |
| **3.8 Electrical Power Systems** | | |
| **3.8.1, AC Sources** | | |
| Verify correct breaker alignment and indicated power | SR 3.8.1.1 | 4.8.1.1.1.a<br>4.8.1.1.2.a.6 |
| Verify starts from standby conditions | SR 3.8.1.2 | 4.8.1.1.2.a.4 |
| Verify DG is synchronized and loaded | SR 3.8.1.3 | 4.8.1.1.2.a.5 |
| Verify day tank volume | SR 3.8.1.4 | 4.8.1.1.2.a.1 |
| Check for and remove accumulated water | SR 3.8.1.5 | 4.8.1.1.2.c |
| Verify fuel oil transfer system operates | SR 3.8.1.6 | 4.8.1.1.2.b |
| Verify diesel starts from standby condition | SR 3.8.1.7 | 4.8.1.1.2.a.4 |
| Verify transfer of AC power sources | SR 3.8.1.8 | 4.8.1.1.1.b |
| Verify DG rejects a load | SR 3.8.1.9 | 4.8.1.1.2.g.2 |
| Verify DG does not trip on load rejection | SR 3.8.1.10 | 4.8.1.1.2.g.3 |
| Verify on a loss of power signal | SR 3.8.1.11 | 4.8.1.1.2.g.4 |
| Verify on an ESF actuation signal | SR 3.8.1.12 | 4.8.1.1.2.g.5 |
| Verify DG's noncritical automatic trips are bypassed | SR 3.8.1.13 | ------ |
| Verify DG operates for ≥ 24 hours | SR 3.8.1.14 | 4.8.1.1.2.g.7 |
| Verify DG state voltage and frequency | SR 3.8.1.15 | 4.8.1.1.2.g.7 |
| Verify DG synchronizes | SR 3.8.1.16 | 4.8.1.1.2.g.9 |
| Verify ESF overrides test mode | SR 3.8.1.17 | 4.8.1.1.2.g.10 |
| Verify interval between each sequenced load block. | SR 3.8.1.18 | 4.8.1.1.2.g.12 |
| Verify on LOOP with an ESF | SR 3.8.1.19 | 4.8.1.1.2.g.6 |
| Verify simultaneously start | SR 3.8.1.20 | 4.8.1.1.2.h |
| *Verify auto-connected loads* | ----- | 4.8.1.1.2.g.8 |
| *Verify fuel oil transfer pump transfers oil* | ----- | 4.8.1.1.2.g.11 |
| *Verify DG lockout relay* | ----- | 4.8.1.1.2.g.13 |
| *Clean fuel oil storage tank* | ----- | 4.8.1.1.2.i.1 |
| *Fuel oil system pressure test (Unit 4 only)* | ----- | 4.8.1.1.2.i.2 |
| **3.8.3, Diesel Fuel Oil, Lube Oil, and Starting Air** | | |
| Verify fuel oil storage tank volume | SR 3.8.3.1 | 4.8.1.1.2.a.2 |
| Verify lubricating oil inventory | SR 3.8.3.2 | 4.8.1.1.2.a.3 |
| Verify DG air start receiver pressure | SR 3.8.3.4 | ----- |
| Check for and remove accumulated water | SR 3.8.3.5 | 4.8.1.1.2.d |
| **3.8.4, DC Sources – Operating** | | |
| Verify battery terminal voltage | SR 3.8.4.1 | 4.8.2.1.a.2 |
| Verify each battery charge supplies | SR 3.8.4.2 | 4.8.2.1.c.3 |

| Surveillance Requirements | TSTF-425 Surveillance Requirement | Turkey Point Surveillance Requirement |
|---|---|---|
| Verify battery capacity is adequate | SR 3.8.4.3 | 4.8.2.1.d |
| **3.8.6, Battery Parameters** | | |
| Verify battery float current | SR 3.8.6.1 | 4.8.2.1.a.3 |
| Verify battery pilot cell float voltage | SR 3.8.6.2 | 4.8.2.1.a.1 |
| Verify battery connected cell electrolyte level | SR 3.8.6.3 | 4.8.2.1.a.1 |
| Verify battery pilot cell temperature | SR 3.8.6.4 | 4.8.2.1.a.1 |
| Verify battery connected cell float voltage | SR 3.8.6.5 | 4.8.2.1.b.1 |
| Verify battery capacity % of the manufacturer's rating | SR 3.8.6.6 | 4.8.2.1.f |
| *Verify battery cell temperature* | ----- | 4.8.2.1.b.2 |
| *Inspect battery for visible corrosion* | ----- | 4.8.2.1.b.3 |
| *Inspect battery for damage or deterioration* | ----- | 4.8.2.1.c.1 |
| *Verify cell to cell and terminal connections* | ----- | 4.8.2.1.c.2 |
| *Verify battery connection resistance* | ----- | 4.8.2.1.c.4 |
| **3.8.7, Inverters – Operating** | | |
| Verify inverter voltage and alignment | SR 3.8.7.1 | ----- |
| **3.8.8, Inverters – Shutdown** | | |
| Verify inverter voltage and alignment | SR 3.8.8.1 | ----- |
| **3.8.9, Distribution System – Operating** | | |
| Verify breaker alignments and voltage. | SR 3.8.9.1 | 4.8.3.1 |
| **3.8.10, Distribution System – Shutdown** | | |
| Verify breaker alignments and voltage | SR 3.8.10.1 | 4.8.3.2 |
| **3.9 Refueling Operations** | | |
| **3.9.1, Boron Concentration** | | |
| Verify boron concentration | SR 3.9.1.1 | 4.9.1.2 |
| **3.9.2, Unborated Water Source Isolation Valves** | | |
| Verify valve positions | SR 3.9.2.1 | 4.9.1.3 |
| **3.9.3, Nuclear Instrumentation** | | |
| Perform Channel Check – Source Range | SR 3.9.3.1 | 4.9.2.a |
| Perform Channel Calibration – Source Range | SR 3.9.3.2 | ----- |
| *Perform Analog Channel Operational Test* | ----- | 4.9.2.c |
| **3.9.4, Containment Penetrations** | | |
| Verify penetration status | SR 3.9.4.1 | 4.9.4 |
| Verify purge valve actuation | SR 3.9.4.2 | ----- |
| **3.9.5, Residual Heat Removal (RHR) and Coolant Circulation – High Water Level** | | |
| Verify one RHR loop in operation | SR 3.9.5.1 | 4.9.8.1.1 |
| *Perform Channel Calibration – RHR flow indicator* | ----- | 4.9.8.1.2 |
| **3.9.6, Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level** | | |
| Verify one RHR loop in operation | SR 3.9.6.1 | 4.9.8.2 |
| Verify breaker alignment and power available | SR 3.9.6.2 | ----- |
| **3.9.7, Refueling Cavity Water Level** | | |
| Verify refueling cavity level | SR 3.9.7.1 | 4.9.10 |