NEXTera ENERGY POINT BEACH

July 3, 2014

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10 CFR 50.90

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

Point Beach Nuclear Plant, Units 1 and 2
Docket 50-266 and 50-301
Renewed License Nos. DPR-24 and DPR-27

License Amendment Request 273
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, NextEra Energy Point Beach, LLC (NextEra) hereby requests to amend renewed Facility Operating Licenses DPR-24 and DPR-27 to Point Beach Nuclear Plant (PBNP), Units 1 and 2, respectively. The proposed amendment would modify the PBNP 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," (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, (ML090850642). Federal Register "Notice of Availability of Technical Specification Improvement to Relocate Surveillance Frequencies to Licensee Control – Risk Informed Specification Task Force (RITSTF) Initiative 5 B, 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.

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

A001
NRR

These changes have been reviewed by the PBNP Station Operations Review Committee.

Pursuant 10 CFR 50.91(b)(1), a copy of this letter is being forwarded to the State of Wisconsin designee.

Should you have any questions regarding this submittal, please contact Mr. Michael Millen, Licensing Manager, at (920) 755-7845.

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

Executed on July 3, 2014.

Very truly yours,

R.V. Wyt for E. McCartney

Eric McCartney
Site Vice President
Point Beach Nuclear Plant

Attachments (5)

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PWCW

Attachment 1

NextEra Energy Point Peach, LLC
Point Beach Nuclear Plant

License Amendment Request No. 273
Description and Assessment

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 Point Beach Nuclear Plant (PBNP), Units 1 and 2 Technical Specificaitons (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 5.0, Administrative Controls, Subsection 5.5, Programs and Manuals. The changes are consistent with NRC approved industry TSTF STS change TSTF-425. Federal Register "Notice of Availability of Technical Specification Improvement to Relocate Surveillance Frequencies to Licensee Control – Risk Informed Specification Task Force (RITSTF) Initiative 5 B, 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

NextEra Energy Point Beach, LLC (NextEra) 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) 4-10, Revision 1, "Risk-Informed Method for Control of Surveillance Frequencies," [Reference 3].

Attachment 2 includes NextEra's documentation with regard to probabilistic risk assessment (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 PRA models without NRC-endorsed standards, including documentation of the quality characteristics of those models in accordance with RG 1.200.

NextEra has concluded that the justifications presented in the TSTF proposal and the safety evaluation prepared by the NRC staff are applicable to PBNP Units 1 and 2 and justify this amendment to incorporate the changes to the PBNP TS.

2.2 Optional Changes and Variations

The proposed amendment is consistent with Standard Technical Specification (STS) changes described in TSTF-425, Revision 3, but NextEra 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 adminstrative 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. NUREG-1431, "Standard Technical Specifications – Westinghouse Plants," Revision 4, Volumes 1 and 2, April 30, 2012, [Reference 5] contains surveillances that are not in the PBNP TS. These surveillances identified in TSTF-425 for NUREG-1431 are not applicable to PBNP. 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 PBNP 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. NextEra has determined that the relocation of the frequencies for these PBNP 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," [Reference 3], 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 assre 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 Decisionmaking: Technical Specifications," dated August 1998 [Reference 7], relative to changes in surveillance frequencies. Therefore, the proposed relocation of the PBNP-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 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).

3.0 REGULATORY ANALYSIS

3.1 No Significant Hazards Consideration

NextEra has reviewed the proposed no significant hazards consideration (NSHC) determination published in the Federal Register July 6, 2009 (74 FR 31996). NextEra has concluded that the proposed NSHC presented in the Federal Register notice is applicable to PBNP Units 1 and 2 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 (ML090850642) and the NRC staff's model safety evaluation published in the Federal Register is applicable to PBNP.

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 Commmission'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

NextEra 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). NextEra concluded that the NRC staff's findings presented therein are applicable to PBNP and the determination is hereby incorporated by reference for this application.

5.0 REFERENCES

1. Technical Specification Task Force (TSTF)-425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control – RITSTF Initiative 5b," March 18, 2009 (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 Probabilisitc Risk Assessment Results in Risk-Informed Activities," Revision 1, January 2007 (ML070240001).

5. NUREG-1431, Standard Technical Specifications – Westinghouse Plants, Revision 4.0, Volumes 1 and 2, April 30, 2012, (ML121000A222 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, (ML072570267)

7. Regulatory Guide (RG) 1.177, "An Approach for Plant-Specific, Risk Informed Decision-Making: Technical Speccifications," August 1998 (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 Initative 5b," April 14, 2010 (ML100990099).

Attachment 2

NextEra Energy Point Peach, LLC
Point Beach Nuclear Plant

License Amendment Request No. 273
Probabilistic Risk Assessment
Adequacy Report

58 pages follow

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 Point Beach Nuclear Plant 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 Point Beach 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 Point Beach 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 Point Beach PRA model update [Reference 4] and internal flood analysis [Reference 5].

2.0 BACKGROUND

2.1 RG 1.200 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 Point Beach PRA History

The Point Beach PRA was originally developed in the early 1990's for the IPE submittal [Reference 6] as a risk assessment of at-power operation of Point Beach addressing internal events. This submittal and supporting documentation was reviewed by internal PRA and systems and operations experts and by independent industry PRA specialists. A Staff Evaluation Report (SER) on the Point Beach IPE was issued by the NRC on January 26, 1995.

The PRA model has been updated many times since it was initially developed to ensure continued fidelity with the as-built, as-operated plant. Notable plant modifications include additional 125 VDC batteries and battery chargers, two additional emergency diesel generators, and two additional motor-driven AFW pumps.

The Point Beach PRA model was initially peer-reviewed in June 2001 by a Westinghouse Owners Group PRA Peer Review Team. The team consisted of a team leader from Westinghouse, two contract PRA reviewers, and three reviewers from PRA groups at other Westinghouse power plants. In general, the review team concluded that the PBNP PRA could be effectively used to support applications involving risk

significance determinations supported by deterministic analyses once the items noted in the report are addressed.

Several additional peer reviews of various Point Beach PRA models have been completed since the initial peer review:

- November 2010 full-scope peer review of the Point Beach Internal Events PRA model.
- June 2011 full-scope peer review of the Point Beach Fire PRA model.
- August 2011 focused-scope peer review of the Point Beach Internal Flooding PRA model.
- October 2011 focused-scope peer review of the Point Beach Internal Events PRA model.
- May 2012 full-scope peer review of the Point Beach High Winds PRA model.
- May 2013 focused-scope peer review of the Point Beach Fire PRA model.
- June 2013 focused-scope peer review of the Point Beach Fire PRA model.

Following these peer reviews, the internal events PRA model was further updated resulting in PRA Model Rev. 5.01, which was finalized in March 2013. The current model of record is Rev. 5.02 which was issued in January 2014.This PRA model of record complies with the ASME/ANS standard (Reference 2) as amended by RG 1.200, Rev. 2 (Reference 3).

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

2.3 Model Change Database

The living PRA is maintained through use of the PRA Model Request (PRAMR) database and word documents which track the status of suggested and pending changes.

These tracking devices are used to store the details of all modifications, proposed and actual, and open or closed, for the Point Beach PRA model. This also includes findings and observations from peer reviews, self-assessments, and issues identified during use and update of the PRA model. 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.

2.4 Point Beach PRA Capability Target

The target capability level for the Point Beach PRA model 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 of the PRA model.

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 actually met in many SRs.

2.5 Assessment Process

The assessment of PRA capability judges the Point Beach 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 any category 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 are also 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 Point Beach PRA for the major Standard parts.

3.1 Parts 2 and 3 - Internal Events and Internal Flooding

Several assessments of technical capability have been made, and continue to be planned, for the PBNP PRA models. These assessments are as follows:

A Full Scope PRA Peer Review for the PBNP PRA model was completed in November 2010. This peer review was performed against the available version of the ASME PRA Standard and Regulatory Guide 1.200, Revision 2 and followed the Follow-On PRA Peer Review process. This peer review included an assessment of the PRA model maintenance and update process. This peer review defined a list of 71 findings for which potential gaps to Capability Category II of the Standard were identified.

A focused peer review of the updated internal flooding study (IF) was conducted in August 2011. This peer review was performed against the available version of the ASME PRA Standard and Regulatory Guide 1.200, Revision 2 and followed the Follow-On PRA Peer Review process. Six of the original 13 findings were not resolved and two new ones were identified during the focused peer review. Attachment A contains a summary of these eight findings, including the status of the resolution for each finding and the potential impact of each finding on this application.

Another peer review of the updated PRA excluding IF was conducted in October 2011. This peer review was performed against the available version of the ASME PRA Standard and Regulatory Guide 1.200, Revision 2 and followed the Follow-On PRA Peer Review process. Twenty Seven of the original findings were not resolved and 4 new ones were identified during the focused peer review. Attachment A contains a summary of these 31 findings, including the status of the resolution for each finding and the potential impact of each finding on this application.

The PRA model was further updated resulting in PBNP PRA model Rev. 5.01 and the current model of record, 5.02. In updating the model, changes were made to the PRA to address most of the remaining findings. Following the update, an assessment concluded that 36 of the findings were fully resolved (i.e., are no longer gaps), and another two were not resolved. No additional gaps were identified during the performance of the review relative to the updated requirements in Addendum B of the ASME PRA Standard and criteria in RG 1.200, Revision 2, including the NRC position stating Appendix A and other NRC-issued clarifications after the 2011 gap analysis had been performed. A summary of the current open items including the partially resolved items is provided in Attachment B.

The remaining gaps will be reviewed for consideration during the future model updates, but are judged to have low impact on the PRA model or its ability to support a full range

of PRA applications. The remaining gaps are documented in a database so that they can be tracked and their potential impacts accounted for in applications where appropriate.

The conclusion is that none of the two open items represents a significant deficiency in the analyses necessary to support the 5b application.

Conclusion

With the exception of the two supporting requirements identified above, the current Point Beach PRA meets all Part 2 (internal event) and Part 3 (internal flooding) CC II requirements of the PRA Standard.

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

The Fire Induced Vulnerability Evaluation (FIVE) methodology was performed for Point Beach as part of the 1995 IPEEE submittal. This effort 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. After completing the FIVE methodology there were fourteen compartments which had a contribution to core damage frequency greater than 1.0E-06/year. Additional fire modeling was performed on these compartments when cost effective, which lowered the number of compartments exceeding 1.0E-06 to nine. The total core damage frequency for the remaining unscreened compartments was 5.1E-05 /year. Following the IPEEE submittal, two additional emergency diesel generators were added to the site significantly reducing this risk.

Point Beach 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 Point Beach 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.

An independent peer review was conducted in June 2011 that included a review of the PRA model, data, and documentation in accordance with ASME Standard ASME/ANS RA-Sa-2009, Capability Category II requirements, as well as RG 1.200, Revision 2. Focused-scope peer reviews were conducted in May 2013 and June 2013 to specifically address Fire Scenario Selection and Analysis (FSS) and Fire Risk Quantification (FQ), respectively. The FSS and FQ F&Os from the 2011 full peer review were reviewed during the focused-scope peer reviews and the peer review teams determined that they could be closed. The few items that were not completely addressed from the 2011 full peer review were captured under new findings.

The peer reviews noted a number of facts and observations (F&O). The F&Os and the disposition of the F&Os are provided in Table V-1. All F&Os that were defined as suggestions have been dis-positioned but not included in Table V-1; however, they will be available for NRC review. No changes have been made to the Fire PRA model since completion of the June 2013 focused-scope peer review that would constitute an

upgrade (based on the definition provided in ASME/ANS RA-Sa-2009). Therefore, no additional focused scope peer review is required to support this LAR.

The Fire PRA meets Capability Category (CC) II in most, but not all cases. A limited number of ASME/ANS areas were identified by the peer review team as meeting Category I only requirements. The capability categories are defined in ASME/ANS RASa- 2009. These are listed in Table V-2 with the planned disposition. The impact of those areas where only the Capability Category I requirement was met was evaluated in Table V-2.

Based on the completion of peer review recommendations and the assessment of deferred items, the PBNP Fire PRA is adequate to support the NFPA 805 Fire Risk Evaluation process.

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 Point Beach PRA is adequate to support this application, with the caveat that the PRA is a conservative representation of the fire risk from operation of the Point Beach Nuclear Plant. 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

Point Beach is sited in an area of very low seismicity. The seismic PRA (SPRA) for Point Beach was performed in response to the seismic portion of the IPEEE. The Point Beach SPRA was developed in accordance with the guidance provided in NUREG-1407 and NUREG/CR-2300, "PRA Procedure Guide - A guide to the Performance of Probabilistic Risk Assessments for Nuclear Power Plants." The enhancements recommended in Appendix 1 to Generic Letter 88-20, Supplement 4 were implemented as part of the development of the SPRA. The major inputs to the SPRA development were the results and insights obtained from plant walkdown activities. The walkdown process was implemented using guidance provided in the SQUG GIP, "Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment," and the EPRI NP-6041-SL, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin." A relay chatter evaluation was performed in accordance with the requirements of NUREG-1407. The calculated core damage frequency was 1.31E-05 per year. The annual core damage frequency lowered to 1.10E-5 per year for the case where the proposed A-46 fixes were included in the seismic PRA quantification. The term large early release frequency (LERF) was not used in the Point Beach IPEEE. Instead the term "Early Containment Failure with Significant Release" was used and had a value of 1.26E-5. 75% of this was due to failure of cable trays inside the cable spreading room. Following the IPEEE submittal, the cable trays' seismic capability was enhanced significantly reducing the containment failure vulnerability. Seismic LERF was estimated as part of the NFPA 805 licensing submittal to the NRC at 1E-6 per reactor year.

Point Beach also used the 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 Point Beach site looking for seismic vulnerabilities.

Staff at Point Beach 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, there were two Seismic Walkdown Equipment List (SWEL) Selection Reports, one for each Unit. Each SWEL Selection Report contains two SWELs. The first consisted of a variety of Seismic Category I 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.

Conclusion

The fact that Point Beach is in a region of low seismicity; multiple seismic walkdowns have been performed to verify the seismic design of equipment important to safety. The seismic risk provided to the NRC from the NFPA-805 submittal is 1E-5 /yr which supports the conclusion that seismic risk at Point Beach is low, but may be a 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 Point Beach IPE and the IPEEE in the 1990s and have not been updated since. These analyses were typically bounding and screening evaluations and 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 used 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 used 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 Energy fleet PRA 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 Point Beach 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 Point Beach 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 Point Beach Nuclear Plant. 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 Point Beach is low, but may be a 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 used 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. PRA 11.0, Internal Events Quantification Notebook.
5. PRA 7.1, Internal Flooding Notebook.
6. Summary Report on Individual Plant Examination for Severe Accident Vulnerabilities Point Beach Nuclear Plant, Units 1 and 2, VPNPD-93-123, June 30, 1993.
7. Summary Report on Individual Plant Examination of External Events for Severe Accident Vulnerabilities Point Beach Nuclear Plant, Units 1 and 2, VPDNP-95-056, June 30, 1995.
8. RG 1.200 PRA Peer Review Against the ASME PRA Standard Requirements For The Point Beach Nuclear Power Plant Probabilistic Risk Assessment, LTR-RAM-II-11-023, May 5, 2011.
9. RG 1.200 PRA Focused Peer Review Against the ASME PRA Standard Requirements For The Point Beach Nuclear Plant Internal Flooding Analysis, RSC 11-25, August 2011.
10. Point Beach Nuclear Plant Focused PRA Peer Review Report, November 2011.
11. Updated Seismic Hazard Results for the Point Beach, St. Lucie, Seabrook, and Turkey Point Nuclear Sites, August 2010.
12. Fire PRA Peer Review of the Point Beach Nuclear Plant Fire Probabilistic Risk Assessment Against the Fire PRA Standard Supporting Requirements from Section 4 of the ASME/ANS Standard, LTR-RAM-II-11-087, October 2011.
13. Results of focused scope peer review on FSS Technical Element for Point Beach Nuclear Plant, May 31, 2013.
14. Results of focused scope peer review on FQ Technical Element for Point Beach Nuclear Plant, June 20, 2013.
15. High Wind PRA Peer Review Against The PRA Standard Supporting Requirements From Section 7 of the ASME/ANS Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessments for Nuclear Power Plant Applications For the Point Beach High Wind Probabilistic Risk Assessment, LTR-RAM-II-12-040, July 2012.

Attachment A – Point Beach PRA Internal Events and Internal Flooding Peer Review Findings					
SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
IE-A1	**Not Met** **Finding IE-A1-01**	**IE-A5 (CC-I)** **IE-B2 (Not Met)** **IE-D2 (Not Met)**	**2010 Peer Review Finding:** ***A systematic process for identifying initiating events was not performed.*** Table 4 (Plant System Review to Determine Special Initiators) in the initiating events report provides an identification of System IE that impact mitigation equipment but ***does not fully address the impact of loss any normally operating system that could results in an IE.*** For example loss of the 4.16 kV AC would lead to an IE due to the loss of component cooling water, loss of instrument air, and loss of CVCS; however, ***there is no quantitative estimate as a basis for screening out this initiating event.*** Loss of HVAC in the Electrical Equipment Room HVAC could result in a reactor trip but no documentation or room heat up calculations are provided to support that loss of the system would not generate a trip. Without a systematic review that accounts for plant-specific features an initiating event can be missed. ***A systematic review should be performed and documented on all normally operating systems. Provide a quantitative basis for screening out the loss of 4.16kV AC bus as an initiator. A recommendation would be that this review would include documentation of possible failure modes and effect on safety system(s) for each system. This is also an ideal location to document possible dual unit impacts.***	**2010 Peer Review Finding Response:** The systematic process **for identifying initiating events** was described in **PRA 2.0, Rev. 5, Initiating Events Notebook** Section 1.2. Section 1.2 has been revised to also provide a list of steps in addition to the descriptive text. The loss of a single 4.16 kV AC bus does not result in a unit trip. This has happened at Point Beach and the unit did not trip. **Therefore** this is not an initiating event. Since this is based on actual plant historical events no quantitative estimate is needed. Loss of HVAC was evaluated in PRA Notebook 05.25. The evaluation for some critical areas was revised and for some areas fault tree models were developed to evaluate the impact of the loss of HVAC. These calculations provide a quantitative basis that these HVAC systems do not contribute and need not be modeled. A systematic review of the plant-specific features was performed **and the results were** documented in Initiating Events Notebook 2.00, Section 1.3.4, "Review of PBNP Design." A systematic review of all normally operating systems was performed. This is documented in Sections 1.3.4, 1.3.5, and Table 4. Additional documentation is provided in each system notebook in Section 05.xx.4, "Initiating Events Review" and Section 05.xx.8, "Failure Modes and Effects Analysis." A quantitative basis for the loss of a 4.16kV AC bus is not needed. The plant has lost a 4.16 kV AC bus and the unit did not trip. Therefore this is not a potential initiating event. Dual unit impacts are discussed in the Success Criteria Notebook, Section 4.1, "Dual Unit Success Criteria." **A quantitative basis for screening out the loss of 4.16kV AC bus is provided in the 2011 peer review response below – however this initiator will not be screened out.** **Documentation of possible failure modes and effect on safety system(s) for each system was addressed in the 2011 finding response - added special initiator column in table 4 of PRA 2.0, Rev. 5, Initiating Events Notebook.** **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

Attachment A – Point Beach PRA Internal Events and Internal Flooding Peer Review Findings					
SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			2011 Peer Review Finding: Section 1.2, 1.3.4, 1.3.5 and Table 4 provide evidence of a systematic review and addresses loss of 4kv and HVAC. Also, the system notebooks address the potential for initiating event (e.g., 05.25 HVAC). However, based on this review, weaknesses still remain and this finding could not be closed. The documentation suggests that an immediate plant trip is required for an equipment failure to be considered an initiating event. ***However, tech spec shutdowns should also be considered (e.g., <24 hr LCO unlikely equipment failure could be fixed within tech spec). The evaluation must be expanded to include this.*** For example the plant experienced a 4KV failure that did not cause a trip but resulted in plant shutdown due to tech specs. Was there a tech spec requirement to shutdown? ***Table 4 should be improved to explain why a special initiator is not required and or how the system is subsumed in another initiating event (Section 1 should have most of the basis along with SY?)***	**2011 Peer Review Plant Response:** **PRA 2.0, Rev. 5, Initiating Events Notebook** Table 4, Special initiator column was expanded to include tech spec shutdowns and improved to include explanation of why special initiator is not required and / or how the system is subsumed by another initiating event. The following text was added to Initiating Events Notebook, PRA 2.0, Section 1.3.5, "Special Initiators for PBNP": "A review of Table 2-1 in DBD-27, "ACCIDENT ANALYSIS REACTOR TRIP VARIABLES, LIMITS, and RESPONSE TIMES" was performed if required to determine if the event described in Table 4, column 3, "Description of Event", would cause a direct or indirect reactor trip. The results of this review are captured in "Special Initiating Event?" column of Table 4." New special initiators were identified as part of this review. 4160 VAC Safeguards buses 1A05 and 1A06 on Unit 1, 2A05 and 2A06 on Unit 2. The Unit is required to shut down if one of the safeguards buses cannot be restored within 6 hours. CAFTA runs were performed to determine the impact of these initiators. A flag file was used to set all initiators to false except Initiating Event Transient with PCS which had the probability set to the 1 year failure probability of a 4160 VAC Vital Switchgear Bus. The flag file also set the 4160 VAC Vital Switchgear bus to failed. The results were the CDF due to a failed 4160 VAC Vital Switchgear bus initiator was between 1.9E-7 and 1.2E-9. LERF was between 3.9E-10 and 9.4E-12. **Because** these **initiators** are not significant contributors they **are not included in the Internal Events PRA.**	
IE-B2	**Not Met** **Finding IE-B2-01**	**IE-A1-01 (Not Met)**	**2010 Peer Review Finding:** The requirement for this element is to use a structured, systematic process for grouping initiating events. For example, such a systematic approach may employ master logic diagrams, heat balance fault trees, or failure modes and effects analysis (FMEA). There is no discussion of the use of a structured, systematic process for grouping initiating events. Ensure a structured, systematic process for grouping initiating events was used, and document the process.	**2010 Peer Review Finding Response:** **PRA 2.0, Rev. 5, Initiating Events Notebook Sections 1.2 and 2.2 were revised to better explain the structured approach.** Section 1.2 now explicitly presents the structured, systematic methodology used in the development of the initiating events. Step 3 of this process is the grouping of identified initiating events. Section 2.2 has been revised to better document the systematic process as per the below. Section 2.3 has been added to present the plant operator interview comments. **ALL issues identified in the 2010 Peer Review Findings were resolved in**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

Attachment A – Point Beach PRA Internal Events and Internal Flooding Peer Review Findings					
SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
				the PRA Model.	
			2011 Peer Review Finding: Sections 1.2 and 2.2 were revised to better explain the structured approach; however, as described for IE-A1-01 the documentation of the review of all systems in Table 4 and basis for IE exclusion is required.	**2011 Peer Review Plant Response:** **PRA 2.0, Rev. 5, Initiating Events Notebook** Column 5, "Special Initiating Event", of Table 4 in the Initiating Event Notebook, 2.0 has been expanded to document the review of the systems and the basis for Special IE exclusion.	
IE-D3	**Not Met** **Finding IE-D3-01**		**2010 Peer Review Finding:** No documentation of sources of uncertainty for initiating events could be found in the IE document. The Standard requires this documentation. Add section discussing sources of uncertainty in the Initiating Events calculation.	**2010 Peer Review Finding Response:** Sources of Uncertainty for this and all other PBNP PRA Notebooks are evaluated in PBNP PRA 11.00 Quantification Notebook. A new Section 5 was added to the IE Notebook to state that Sources of Uncertainty are evaluated in PRA 11.00, the Quantification Notebook. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
			2011 Peer Review Finding: Section 1.3.6 of IE Notebook identifies assumptions, which are a key source of uncertainty and Section 5 of IE Notebook references QU for uncertainty, but there is no updated QU Notebook	**2011 Peer Review Plant Response:** Section 5.0 of the PRA Notebook 11.0, Quantification Notebook contains a discussion on the sources of uncertainty and their impact to the PRA. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
AS-B1	**Not Met** **Finding AS-B1-01**		**2010 Peer Review Finding:** This element states that for each modeled initiating event, identify mitigating systems impacted by the occurrence of the initiator and the extent of the impact. Include the impact of initiating events on mitigating systems in the accident progression either in the accident sequence models or in the system models. ***Currently two separate models are being maintained for PBNP - one for Unit 1 and one for Unit 2. By maintaining two separate models, the full impact of dual unit initiating events, and the importance of failures of shared equipment is not adequately addressed.*** The dual unit impact of shared systems, especially under dual unit initiating	**2010 Peer Review Plant Response:** The two separate top models being maintained for PBNP address the full impact of dual unit initiating events. The PBNP PRA currently uses 2 separate top gates, one for Unit 1 and 1 for Unit 2. This has been the case historically and the 2 models are maintained in parallel. <u>The standard does not require a single top model for a multiple unit site.</u> While there are some shared systems between the 2 PBNP units (electrical, service water) and some additional systems that have limited cross-connect capabilities (auxiliary feedwater, component cooling water, instrument air, station air), identical fault tree logic is used in both models for these systems and the commonalities and impacts are properly accounted for in the logic models. For example, the AFW system model considers the availability of AFW flow to the opposite unit to determine what pumps can be considered for the unit in question. Some additional gates were added to the model to better reflect dual unit impacts.	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

Attachment A – Point Beach PRA Internal Events and Internal Flooding Peer Review Findings					
SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			events, is very important from a risk perspective, and will become even more important when the PRA is converted to a Fire PRA model. **A single top PRA model that reflects both Units would explicitly address the dual unit impacts and the importance of system/equipment failures.** **Challenge:** The two separate top models being maintained for PBNP address the full impact of dual unit initiators. **Response:** From the team review during the week, and our discussions with the PRA people, ***it did not appear that dual unit initiators were being addressed appropriately.*** Given the events at Fukushima, this is now of particular concern. In particular, in a dual Unit initiating event – the equipment on the opposite Unit will most likely NOT be available to respond to the initiating event – it will be dedicated to its Unit until its Unit is placed in a safe, stable state, or until it is shown that it is not needed for its Unit. There was no evidence that this was taken into consideration at all in the individual models. ***Depending upon the Dual Unit Initiating Event, cross-tied/shared systems will most likely have their cross-connect valves closed to isolate the two Units from each other – and will require an operator action to re-open the valves if the system is allowed to be re-cross connected - this consideration was not seen in the individual models. There is also no evidence that the HFEs associated with an event are modified for a dual-unit initiator when Operators will be at a premium, and their availability to respond to outside the control room actions will be impacted.***	The following changes were made to the model in response to F&O AS-B1-01, the F&O related to a single model for both units: - Under existing gate GAFM2500, add new AND gate GAFM2501 with two new inputs. One input is new OR gate GAFM2502 and the other input is new OR gate GAFM2503. New OR gate GAFM2503 has as inputs existing initiating events INIT-T1G, INIT-T1GB, INIT-TIP, INIT-T1W, INIT-TD1, INIT-TD2, INIT-TIA, INIT-TSW. - Under gate GAFW1800, add new AND gate GAFW1801. Under new AND gate 1801, add OR gate GAFM2503. - Under gate GAFM2900, add new AND gate GAFM2901. Under new AND gate add OR gate GAFM2503. The Technical Specifications were reviewed to assure that the impact of the status of the opposite unit is correctly modeled and it was determined that there is no impact from unit status. The modeling of the common systems and systems with cross-tie capability described above was reviewed and the modeling correctly captures the dependencies *between units.* There is no requirement for a single top event for a multiple unit site. Additionally, none of the duel unit site models that the PRA team is familiar with have a single top model for multiple units. If a single top model were produced it would still be solved at the individual unit level. It is not clear what the meaning would be of solving for simultaneous core damage. **Furthermore the 2011 focused peer review also noted that *"It does not appear that the Standard requires a single top and the models for each unit appears correct for quantifying risk of each unit with shared equipment. "*** **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	
			2011 Peer Review Finding: It does not appear that the Standard requires a single top and the models for each unit appear correct for quantifying risk of each unit with shared equipment.	**2011 Peer Review Plant Response:** There are no longer any front line systems shared between units. • Auxiliary feedwater is now unit specific.	

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			Also, Point Beach can supply both units with a single diesel. ***What is not clear is whether all dependencies between unit shared systems have this capability and the importance of any that cannot supply both units.*** Given recent events and the potential importance of dual unit events, this finding will have to remain open.	• Startup Steam Generator pumps which were the motor driven AFW pumps are shared between units. • CSTs are shared but levels are maintained to accommodate an accident on one unit and hot shutdown on the other unit. **The following list describes the dependencies between systems shared between the units:** • 13.8 KV - Designed for normal loads on one unit which are greater than accident loads on both units. • 4160 VAC - Designed for normal loads on one unit which are greater than accident loads on both units. • 480 VAC - Unit Specific • EDG - Can supply both units with a single diesel • 120 VAC - Unit Specific • 125 VDC - The batteries are designed for accident on one unit and hot standby on other unit. • Accumulators - Unit Specific • SI RHR - Unit Specific • AFW - Unit Specific (See note above) • Containment Spray - Unit Specific • Fan Coolers - Unit Specific • Containment Isolation - Unit Specific • Service Water System - Success criteria of two pumps can support accident on one unit and hot shutdown on other unit. • Component Cooling Water - Unit Specific • Actuation Systems - Unit Specific • Main Feedwater - Unit Specific • Main Steam - Unit Specific • Reactor Coolant System - Unit Specific • CVCS - Unit Specific • Fire Protection - Accident loads on both units are less than fire protection loads. Used to make up CSTs and cool TDAFWP bearings. • Instrument/Service Air - Accident loads on both units are less than normal operating loads. • Fuel Oil - Designed to support EDG with accident on one unit and hot shutdown on other unit. **The list above clarifies** dependencies between unit shared systems, which have the capability as required to cope with dual unit shutdowns. **ALL issues identified in the 2011 Peer Review Findings were resolved in**	

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				the PRA Model.	
AS-B3	**Not Met** **Finding AS-B3-01**	**SY-B6 (Met)** **SY-B14 (Not Met)**	**2010 Peer Review Finding:** This element is associated with identifying and modeling the effects of the phenomenological conditions created by the accident progression. Phenomenological impacts include: generation of harsh environments affecting temperature, pressure, debris, water levels, humidity, etc. that could impact the success of the system or function under consideration. ***The effects of phenomenological conditions created by the accident progression of Main Steam Line Breaks or Feed Line Breaks outside containment are not adequately addressed.*** In particular, the analysis states that MSLB's outside containment "result in no adverse Containment atmosphere" or "there are no adverse environmental conditions" from the event. Because of the accident sequence itself - ***there will be a steam environment in the vicinity of the break, but this adverse environment is not addressed.*** Because of the potential ***impact on non-qualified equipment and Operator actions in areas outside of containment that can be subject to the effects of MSLBs outside containment, the potential adverse conditions need to be identified and their impact of equipment and actions in the areas need to be addressed. Additionally, no discussion on debris generated in Containment due to LOCAs or MSLBs inside containment can be found.*** Evaluate the phenomenological conditions created by the accident progression and include the impacts of any adverse conditions in the fault tree model and documentation. Need to evaluate potential steam environments outside containment, Main Feed breaks outside Containment, HELB issues, debris generation inside containment, potential NPSH impacts, etc.	**2010 Peer Review Plant Response:** Section 5.4.6 and Table 5.4.5 of the AS Notebook were enhanced with the following: "Large LOCAs may also create an environment (i.e., pressure, temperature, humidity, debris generation) that could impact equipment. This is addressed in the Success Criteria Notebook (Reference 8.1)." Section 5.5.6 and Table 5.5.4 of the AS Notebook were enhanced with the following: "Events inside containment may create an environment (i.e., pressure, temperature, humidity, debris generation) that could impact equipment. This is addressed in the Success Criteria Notebook (Reference 8.1). For events outside containment, collateral damage is explicitly included in the model. For secondary line break events in the turbine building, a loss of all MFW and Instrument Air is assumed. Breaks in the Aux building also impact equipment. For these cases, only qualified equipment or equipment not directly. affected is available" Section 3.4 of the SC Notebook was enhanced (and Reference 4 was added in Section 9) with the following: "In addition, Section 1.4 and Section 9 (assumption 6) of the SI/RHR System Notebook (Reference 4) address the issue of debris in containment, concluding that debris has no impact on containment sump recirculation." The above enhancements address the concerns of the F&O regarding the environmental impacts of Large LOCAs (Small and Medium LOCAs produce much less force; see responses to GSI-191) and Secondary Line Breaks. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	***NO IMPACT*** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

Attachment A – Point Beach PRA Internal Events and Internal Flooding Peer Review Findings					
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			2011 Peer Review Finding: Sections 5.4.6, 5.5.6 and tables 5.4.5, 5.5.4 of AS Notebook were revised to address this F&O, ***but there was insufficient information to address HELB outside containment.*** Plant response refers to SC Notebook Section 3.4 which does not contain anything relevant. The details of HELB (e.g., FW and MS) and the impacts in the Aux Bldg and Turbine Bldg are not described. The RHR system notebook was revised to address issue of containment sump debris and plugging of SI injection path flow orifices.	**2011 Peer Review Plant Response:** Accident Sequence Notebook 3.2, Section 6.5.1 was revised to include discussion of HELB and the impacts on the Aux Bldg and Turbine Bldg. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
AS-B6	**Not Met** **Finding AS-B6-01**	**SY-A5 (Met)** **SY-A21 (Not Met)** **SY-B6 (Met)** **SY-B15 (Met)**	**2010 Peer Review Finding:** This element is associated with ensuring that plant configurations and maintenance practices which create dependencies among various system alignments are defined and modeled in a manner that reflects these dependencies, either in the accident sequence models or in the system models. Because of electrical bus limitations, Point Beach has some unique system alignment restrictions. ***Currently these system alignment restrictions are not reflected in the PRA model. In particular, there are system alignment restrictions associated with the System Air and CVCS systems such that specific System Air Compressors cannot be in operation if specific CVCS pumps are in operation.*** ***A review of the Normal System Operating Procedures should be performed to identify the unique PBNP system alignments and restrictions. Once the unique system alignments and restrictions are identified, the limitations should be reflected in the PRA fault tree models.***	**2010 Peer Review Plant Response:** Text was added to the AS Notebook, Section 5.6.3, and the EDG and 4160 VAC Notebooks that explains why alignment restrictions do not impact the model. Point Beach Electrical Loads Limitations Per Tim Lensmire, the Point Beach electrical engineer knowledgeable on electrical loads, was interviewed on 2-17-2011 by Stanley Guokas to address load management for normal alignments at Point Beach. The first is OI-35C which Tim says in theory should go away after the **March 2011** Unit 2 outage once the EPU modifications have been implemented. The second and third are AOP-22 for Unit 1 and Unit 2. These AOP's provide for load management on the diesel generators following a loss of offsite power. Additionally, it was noted that additional loading restrictions may be placed in effect when maintenance is performed on electrical equipment. 13.8KV or 4160 Volt Electrical Load Management When maintenance is performed on some 4160 volt transformers bus load restrictions are placed in effect: • 3.5 When removing 1X-03, Unit 1 High Voltage Station Auxiliary Transformer, or 1X-04, Unit 1 Low Voltage Station Auxiliary Transformer, from service, the following additional measures will ensure operability of offsite power from a potential degraded voltage condition during a unit trip: (Ref 6.6.8 & Attachment F) • For any unit in Mode 1 - defeat one of that units 4160V fast bus transfer, typically the A-03 to A-01 Bus Tie due to the turbine auxiliaries powered from A-02. For any unit in Modes 5, 6 or defueled - maintain that units A01 and A02 4160V motors OFF.	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

Attachment A – Point Beach PRA Internal Events and Internal Flooding Peer Review Findings					
SR	Category and Finding	Other Affected SRs	PEER REVIEW FINDINGS	RESOLUTION	IMPACT ON APPLICATION
				• 3.6 When re-energizing the 1X-04 transformer the 13.8KV bus should be aligned to the 1X-03 transformer to reduce possible perturbations to opposite units online equipment. These transformers are the normal supply to the class 1E buses. As such, these transformers would not be taken out of service while the plant is operating. The model assumes that no routine maintenance would be performed on these transformers during unit operation. **Therefore, this load restriction has no impact on the model.** OI-35C – 480 Volt Electrical Load Conservation The loads considered as discretionary are charging pumps 1P-2A and 1P-2B and instrument air compressor K-2A. To meet the loading requirement, first one of these loads is secured off (no auto-start). If this configuration does not meet the loading requirement, then 2 of these loads are secured off (no auto-start). However, these load management measures are not utilized when an AOP/EOP is in effect. The load management issues addressed in OI-35C will be resolved by modifications being made during the upcoming (March 2011) Unit 2 refueling outage. **Therefore, the electrical load considerations contained in OI-35C need not be considered in the model.** AOP-22 Unit 1 – EDG Load Management This procedure is applicable when the EDGs are running, loaded, and the bus being supplied is isolated. If the load on a EDG exceeds the 200 hour limit the operators isolate unnecessary plant equipment per Attachment A, Unit 1 Electrical Loads (for EDGs G-01 and G-02) or isolate non-safeguards bus 1B-40 (for EDGs G-03 and G-04) as per Step 1, Response Not Obtained. If the load on a EDG exceeds the 2,000 hour limit the operators isolate additional unnecessary plant equipment per Attachment A. It should be noted that Attachment A simply defines all of the potential loads by bus and does not prioritize these loads or indicate what loads should be shed first. Since Attachment A does not prescribe what loads should be retained or shed, it is not possible to determine directly what impact this restriction has on the model. Since the PRA models the first 24 hours following a Unit trip the applicable loading limits for the PRA are the 2000 hour ratings, or 2,850 kW for G-01 and G-02 and 2,848 kW for G-03 and G-04. An analysis of the loads necessary to safely shutdown both units with a single diesel generator has been	

Attachment A – Point Beach PRA Internal Events and Internal Flooding Peer Review Findings					
SR	Category and Finding	Other Affected SRs	PEER REVIEW FINDINGS	RESOLUTION	IMPACT ON APPLICATION
				performed and it is possible with any single diesel, subject to equipment failure. These facts, and the statement that loads are started and stopped "as directed by the plant procedures" (Step 2), indicate that the necessary equipment to safely shutdown the unit(s) would be identified by the operating procedures in effect at time and operated at direction of the operators. Therefore, no additional modeling is necessary to capture any potential limitations. To ensure that excessive loads are not credited in the PRA, the minimal set of equipment necessary to safely shutdown the unit(s) for the Loss of Offsite Power and Station Blackout accident sequences were reviewed and compared against the analysis of the loads necessary to safely shutdown both units with a single diesel generator mentioned above. **This demonstrated that there are no additional impacts of electrical load limitations on the PRA models.** AOP-22 Unit 2 – EDG Load Management This procedure is applicable when the EDGs are running, loaded, and the bus being supplied is isolated. If the load on a EDG exceeds the 200 hour limit the operators isolate unnecessary plant equipment per Attachment A (for EDGs G-01 and G-02) or isolate non-safeguards bus 1B-40 (for EDGs G-03 and G-04) as per Step 1, Response Not Obtained. If the load on a EDG exceeds the 2,000 hour limit the operators isolate additional unnecessary plant equipment per Attachment A, Unit 2 Electrical Loads. It should be noted that Attachment A simply defines all of the potential loads by bus and does not prioritize these loads or indicate what loads should be shed first. Since Attachment A does not prescribe what loads should be retained or shed, it is not possible to determine directly what impact this restriction has on the model. Since the PRA models the first 24 hours following a Unit trip the applicable loading limits for the PRA are the 2000 hour ratings, or 2,850 kW for G-01 and G-02 and 2,848 kW for G-03 and G-04. An analysis of the loads necessary to safely shutdown both units with a single diesel generator has been performed and it is possible with any single diesel, subject to equipment failure. These facts, and the statement that loads are started and stopped "as directed by the plant procedures" (Step 2), indicate that the necessary equipment to safely shutdown the unit(s) would be identified by the operating procedures in effect at time and operated at direction of the operators. Therefore, no additional modeling is necessary to capture any potential limitations. To ensure that excessive loads are not credited in the PRA, the minimal set of equipment necessary to safely shutdown the unit(s) for	

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				the Loss of Offsite Power and Station Blackout accident sequences were reviewed and compared against the analysis of the loads necessary to safely shutdown both units with a single diesel generator mentioned above. **This demonstrated that there are no additional impacts of electrical load limitations on the PRA models.**	
			2011 Peer Review Finding: Section 5.6.3 of AS Notebook and EDG & 4Kv system notebooks were revised. OI-35c will not be applicable after upcoming Unit 2 outage (480 V). AOP-22 addressed load management on EDGs. Additional restrictions on 13.8 and 4 Kv, but these maintenance alignments are not conducted at power. ***Appears that load management failure is a possible failure mode for EDGs that is not modeled.*** AOP-22 indicates load management is critical however could not find basis concluding it could be neglected as an EDG failure. Plant response indicated that HEP "HEP-416-U1-A-3-4" included Load Management within a cross-tie action. This was reviewed in HRA Calculator (HRAC) and no tasks for load management were identified and no mention of load management was visible in the HRA entry. Similar AC cross-tie actions were also reviewed in HRAC and likewise no load management information was identified. Also, the Load list in AOP-22 was summed to yield over 7000kW. Further, Calculation 2004-002 "Emergency Diesel Loading" appears to credit operator actions for various situations. For example, Page 215 has negative loads (i.e., loads that are secured) for "SW Reduction", "Turn off MDAFP", and "Turn Off SI Pump (P-15)". ***Thus, in theory it seems possible to overload an EDG (Load limit ~3000kW). No Modeling of Operator to manage EDG Loads found. (See SY-21-01).***	**2011 Peer Review Plant Response:** The HFE of failure of the operators to properly manage EDG loads was not modeled due to the extremely low probability of the opportunity for this error to result in a loss of the EDG ever occurring. In order for this HFE to be viable, there must be a loss of offsite power, a demand for the safety injection pumps (i.e., a LOCA), and a random failure of one of the EDGs. Furthermore, the probability of this HFE is expected to be low due to the clarity of the procedural guidance and the frequent training given to the operators on proper EDG load management Within AOP-22, a note specifically states that EDG Loading is critical when the site is reduced to a single EDG and the EDG is required to support the equipment required for Safety Injection. A calculation is presented below, which calculates the probability of using this procedure: • SI = 1E-2 Includes LOCAs and Steam/Feed line breaks since excessive cooldown will generate an SI • LOOP = 3E-2 Sum of all LOOPs • Gas Turbine = 1E-1 Out for Maintenance • 3 EDGs = 7E-6 Common Cause Failure to Run 1st hour or CCF run 23 hours. Probability of using this procedure with only 1 EDG = 1E-2 * 3E-2 * 1E-1 * 7E-6 = 2.1E-10.	
AS-B7	**Not Met** **Finding AS-B7-01**		**2010 Peer Review Finding:** This element is associated with modeling time-phased dependencies (i.e., those that change as the accident progresses, due to such factors as depletion of resources, recovery of resources, and changes in	**2010 Peer Review Plant Response:** The PRA model reasonably accounts for the impacts of time phased dependencies. The model has been improved in 3 areas to better reflect the impact of time	**NO IMPACT** **Removing these**

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			loads) in the accident sequences. Examples are: (a) For SBO/LOOP sequences, key time-phased events, such as: (1) AC power recovery (2) DC battery adequacy (time-dependent discharge) (3) Environmental conditions (e.g., room cooling) for operating equipment and the control room ***Although time-phased recoveries appear to be considered at PBNP, it is not clear that they are addressed appropriately and completely. For example, in the HVAC notebook, there are several rooms that are expected to exceed the design limits for the equipment in them, but failure of HVAC to the rooms are not modeled. Additional justification for why HVAC to those rooms is not required needs to be addressed.***	phased events. First, the Power Recovery Convolution has been revised. This calculation determines the likelihood of the recovery of offsite power at the specific times that the MAAP and the RCP Seal LOCA analyses identified as being critical to the development of accident sequences. The current Convolution analyses were developed specifically for SBO (no power available from any source) and are therefore not applicable to a partial power situation such as LOOP. Additionally, the modifications to the DC modeling resolve the bulk of the cutsets in LOOP that give the appearance of being long term SBO sequences. Second, the HVAC Notebook analyses have been revised. Additional consideration was given to the available information and additional analyses were performed to quantitatively support the conclusions presented in the notebook. Third, the modeling and tagging of battery depletion and the recovery rules for restoration of power to a DC bus have been revised. The previous model had a single tag to identify a depleted bus and the HEP dependencies are cued off of this tag. This resulted in the failure of a single DC bus effectively failing all DC power (a modeling error). This has been revised such that there is a unique tag for each DC bus and the cutsets in LOOP that looked like they should be in SBO (erroneous cutsets) have been modified to correctly reflect the loss of DC at a specific bus and not the loss of all DC power. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**conservatisms *may be* considered in the future – this finding will remain open. but does not impact the PRA results.**
			2011 Peer Review Finding: The model was improved in 3 areas to better reflect the impact of time phased dependencies as described above. HVAC notebook was updated and model includes HVAC as appropriate. ***However, the Model is still conservative because LOOP recovery for non-SBO scenarios is still neglected and the basis for this is inadequate. Also, DC life is still assumed to be 1 hour when realistic battery life is much greater (DC notebook does not mention true battery life other than full load test takes 2 ½ days). In the convolution analysis, credit is not even taken for the one battery hour. As a minimum greater detail is required to document these assumptions and their impact on the results (QU). Since the 5.00 model is being***	**2011 Peer Review Plant Response:** In the current convolution calculation for LOSP, LOOP recovery is applied to only SBO sequences and DC battery life is not considered (i.e. **assumed to** Fail at 0 hours). This is conservative since recoveries which could be applied to reduce CDF and LERF are not applied. **Removing these conservatisms may be considered in the future – this finding will remain open but does not impact the PRA results.**	

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			reviewed the QU results will not address additional model changes being incorporated by NEXTERA.		
SC-A6	**Not Met** **Finding SC-A6-02 Doc Only**	**AS-C3 (Not Met)**	**2010 Peer Review Finding:** This SR requires that success criteria be confirmed to be consistent with features procedures and operating philosophy of the plant. Point Beach set the upper end of their small break LOCA event to 2 inches based on generic information from NUREGs. However, in the accident sequence notebook, Point Beach made a statement to the effect that over much of the range of their small break LOCA spectrum, secondary side heat removal side was not needed (see small LOCA assumptions section). However, in Section 6.2.3 of PRA 3.2, it is stated "The small LOCA event tree (Event Tree Notebook, Figure S2) applies to breaches in the RCS which are large enough that the break flow exceeds the capacity of the normal reactor makeup system. The break size, however, is not large enough to provide core decay heat removal." These two statements are inconsistent. A review of the success criteria calculations did not reveal any calculations to determine the upper end of the small LOCA spectrum based on the need for secondary side heat removal. Run a set of MAAP calculations to determine the break size that is just sufficient to remove decay heat and depressurize the primary side. Use the break size thus determined as the lower bound for the medium LOCA and upper bound for the small LOCA. Use the results to also clarify the small LOCA definition in the SC notebook, the AS notebook and the IE notebook and make them all consistent.	**2010 Peer Review Plant Response:** The Westinghouse Design Basis Analysis divides LOCAs into two sizes, large and small. The small LOCA upper end break size is 6 inches diameter. The basis for this division is that large LOCAs exhibit high break exit velocities such that mitigation flows (low pressure injection, accumulators, etc.) bypass the core and exit the break without providing core cooling. This occurs until the end of the "blowdown phase", when the break exit velocities drop such that mitigation flows reach the core to provide core cooling. As such, different design basis codes (SATAN/WREFLOOD for large LOCAs and NOTRUMP for small LOCAs) must be used for the different size LOCAs. The MAAP code cannot be used to analyze the short term timeframes of large LOCAs that produce the conditions that result in core bypass (see Section 3.4 of PRA 3.2). However, MAAP is reasonable for analyzing the longer term time frames of all LOCA sizes. The results of MAAP run PB1ML-25 (4" LOCA without AFW or cooldown and depressurization) indicate that RHR injection only just barely averts core damage. This would indicate that the large LOCA success criteria could be used down to approximately 4 inches. However, the 6" break size is a reasonable point at which to differentiate between PRA-defined large and medium LOCAs based on the core bypass characteristics described above. The differentiation point between PRA-defined medium and small LOCAs is 2 inches diameter. MAAP run PB1ML-06 shows that sufficient energy is removed via the break that secondary cooling is not required as long as high head SI is successful. However, unlike the 6" and 4" medium LOCAs, a 2" LOCA does require AFW and operator-initiated cooldown and depressurization to use RHR if high head fails (MAAP run PB1SL-17 for failure of high head recirculation, PB1SL-14 for failure of high head injection). As one can see, the requirements for AFW and cooldown and depressurization that exist for medium LOCA successful sequence 3 are set by the lower bound of the medium LOCA (2 inch diameter). One could move more of the break spectrum in the 2" to 4" range into the small LOCA realm such that there was no requirement for AFW and cooldown and depressurization for the medium LOCA. However, there would be more break spectrum in the small LOCA that would not require secondary heat removal if high head injection was available. Conversely, one could move more of the break spectrum in the 2" to 1" range into the medium LOCA realm such that there was always a requirement for secondary heat removal if high head	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
				injection was available for the small LOCA. However, there would be more break spectrum in the medium LOCA that would require AFW and cooldown and depressurization, and possibly feed and bleed for failure of AFW. In other words, there are competing conditions such that a "perfect" break point" may not be attainable. What this means is that the 2 inch LOCA is a reasonable break size for the differentiation point between PRA-defined medium and small LOCAs. Therefore, no changes were made to the Point Beach break size spectrum. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	
			2011 Peer Review Finding: Plant response to [2010] peer review seems reasonable but has to be included in the SC (and or IE and AS) notebook to resolve this finding (important documentation based on previous peer review).	**2011 Peer Review Plant Response:** The response to F&O SC-A6-02 was added to PRA 3.2, Success Criteria Notebook, Section 6.2.3.	
SY-A21	**Not Met** **Finding SY-A21-01**		**2010 Peer Review Finding:** *This element states that system conditions that* cause a loss of desired system function, (e.g., excessive heat loads, excessive electrical loads, excessive humidity, etc.) should be identified. A review of various electrical system notebooks and the EDG system notebook did not identify any consideration of excessive electrical loads on the busses or the EDG. With the electrical margin for some of the busses and the EDGs at Point Beach being minimal to non-existent, a review for potential excessive loading conditions needs to be performed and documented. In particular, a look at Operators starting equipment in response to redundant equipment failures, and failures of equipment to fully load shed should be considered, documented, and explicitly included in the model as appropriate. Currently, with the exception of the EDG start logic, load shed and UV detection is embedded in the bus failure rates, and needs to be explicitly modeled because of the excessive loading concern.	**2010 Peer Review Plant Response:** *Plant Response: Excessive Electrical Loads are addressed in the response to* F&O AS-B6-1. The PRA model requires ALL of the circuit breakers associated with a bus that are required to be shed (be opened) prior to closing a circuit breaker for a new power source to be aligned to the bus. This is explicitly modeled and is not imbedded in the bus failure rates as was thought by the reviewers. No model change is required to address this comment. The limitations associated with the 4.16 KV transformers are related to maintenance that would not be performed during operation, so there is no impact on modeling. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			With the electrical margin for some of the busses and the EDGs at Point Beach being minimal to non-existent, a review for potential excessive loading conditions needs to be performed and documented. In particular, a look at Operators starting equipment in response to redundant equipment failures, and failures of equipment to fully load shed should be considered, documented, and explicitly included in the model as appropriate. Currently, with the exception of the EDG start logic, load shed and UV detection is embedded in the bus failure rates, and needs to be explicitly modeled because of the excessive loading concern.		
			2011 Peer Review Finding: AOP-22 for Unit 1 and Unit 2 provide for load management on the diesel generators following a loss of offsite power. Procedure direct operators to isolate/strip unnecessary loads if the EDG load exceeds the 200/2000 hour limit. To ensure that excessive loads are not credited in the PRA, the minimal set of equipment necessary to safely shutdown the unit(s) for the Loss of Offsite Power and Station Blackout accident sequences were reviewed and compared against the analysis of the loads necessary to safely shutdown both units with a single diesel generator mentioned above. This demonstrated that there are no additional impacts of electrical load limitations on the PRA models. See also discussion in AS-B6-01.	**2011 Peer Review Plant Response:** The HFE of failure of the operators to properly manage EDG loads was not modeled due to the extremely low probability of the opportunity for this error to result in a loss of the EDG ever occurring. In order for this HFE to be viable, there must be a loss of offsite power, a demand for the safety injection pumps (i.e., a LOCA), and a random failure of one of the EDGs. Furthermore, the probability of this HFE is expected to be low due to the clarity of the procedural guidance and the frequent training given to the operators on proper EDG load management. Within AOP-22, a note specifically states that EDG Loading is critical when the site is reduced to a single EDG and the EDG is required to support the equipment required for Safety Injection. A calculation is presented below, which calculates the probability of using this procedure: SI = 1E-2 Includes LOCAs and Steam/Feed line breaks since excessive cooldown will generate an SI LOOP = 3E-2 Sum of all LOOPs Gas Turbine = 1E-1 Out for Maintenance 3 EDGs = 7E-6 Common Cause Failure to Run 1st hour or CCF run 23 hours. Probability of using this procedure with only 1 EDG = 1E-2 * 3E-2 * 1E-1 * 7E-6 = 2.1E-10. ***[refer to comments in AS-B6-01]*** **ALL issues identified in the 2011 Peer Review Findings were resolved in**	

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				the PRA Model.	
SY-B3	**Not Met** **Finding SY-B3-01**		**2010 Peer Review Finding:** ESTABLISH common cause failure groups by using a logical, systematic process that considers similarity in: (a) Service conditions (b) Environment (c) Design or manufacturer (d) Maintenance JUSTIFY the basis for selecting common cause component groups. Candidates for common cause failures include, for example: (a) Motor-operated valves (b) Pumps (c) Safety-relief valves (d) Air-operated valves (e) Solenoid-operated valves (f) Check valves (g) Diesel generators (h) Batteries (i) Inverters and battery charger (j) Circuit breakers For initiating events, common cause failure groups for the "failure to run" or "failure to operate" modes that involve a normally operating component failing followed by the failure of the standby failure group use an exposure time of 24 hours. Because the exposure in which the normally operating component can fail is one year, and because CCF parameters are dimensionless, the use of 24 hours is incorrect. It should be one year. The times can be changed and then the initiating event re-quantified.	**2010 Peer Review Plant Response:** Plant Response: Because the exposure in which the normally operating component can fail is one year, and because CCF parameters are dimensionless, the use of 24 hours is incorrect." This statement is incorrect. In all of the analyses of common cause data events to date, the definition of the parameter is "failure of identical components due to the same cause within a 24 hour period." Thus, CCF parameters are NOT dimensionless; they are a fraction of failures that occur in a 24 hour period. CCF parameters not dimensionless. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
			2011 Peer Review Finding: Plant response could be improved as it is common practice in most PRAs to decouple standby pump failures from CCF of running pumps over 8760 hours. Although it is slightly optimistic there is no data for	**2011 Peer Review Response:** Common Cause Failure of Component Cooling Water Pumps to start and run has been added to the model. The delta CDF due to this change was	

<table>
<tr><th>SR</th><th>Category and Finding</th><th>Other Affected SRs</th><th>PEER REVIEW FINDINGS</th><th>RESOLUTION</th><th>IMPACT ON APPLICATION</th></tr>
<tr><td></td><td></td><td></td><td>failure of one pump over 8760 and then common cause failure of the second (given start success) to fail before repair of the first pump. This modeling approach needs to be clearly described in the system notebooks. SW modeling was improved using this approach. Note that CCW has one operating pump and one standby pump thus there is no CCF to run for an initiating event using this approach. However, there is no CCF to run or start in the CCW mitigation model, which is required.</td><td>4.25E-8 on Unit 1 and 4.28E-8 on Unit 2.

There was no delta LERF on either Unit.

Sensitivity of common cause failures for component cooling water pumps in mitigation section of model.

CC--MDP-FS-1-11A = 1.51E-03/demand
Beta = 2.31E-02 NRC Common Cause Database MDP FS

Common cause failure to start = failure rate * Beta

Common cause failure to start = 1.51E-03 * 2.31E-02 = 3.49E-05/demand
Type Code CC- MDP CM 11S = 3.49E-05/demand

CC--MDP-FR-1-11A = 5.86E-06/hour
Beta = 5.86E-02 NRC Common Cause Database CC MDP FR

Common cause failure to run = failure rate * Beta

Common cause failure to run = 5.86E-06 * 5.86E-02 = 3.43E-07/hour
Type Code CC- MDP CM 11R = 3.43E-07/hour

Results:
<table>
<tr><th>U1 CDF No CCW CCF</th><th>1 CDF CCW CCF</th><th>U2 CDF No CCW CCF</th><th>U2 CDF CCW CCF</th><th>U1 LERF No CCW CCF</th><th>U1 LERF CCW CCF</th><th>U2 LERF No CCW CCF</th><th>U2 LERF CCW CCF</th></tr>
<tr><td>5.34E-06</td><td>5.39E-06</td><td>5.34E-06</td><td>5.38E-06</td><td>7.83E-08</td><td>7.83E-08</td><td>8.13E-08</td><td>8.13E-08</td></tr>
<tr><td>DELTA</td><td>4.25E-08</td><td>DELTA</td><td>4.28E-08</td><td>DELTA</td><td>0.00E+00</td><td>DELTA</td><td>0.00E+00</td></tr>
</table>
The change in CDF for both units was an increase of 4E-8 and there was no change in calculated LERF. Therefore, the change has an insignificant impact on CDF and LERF for both Unit 1 and Unit 2.

The changes to the fault trees are documented in the appropriate System Notebook.

ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.</td><td></td></tr>
<tr><td>HR-A3</td><td>Not Met

Finding HR-A3-</td><td></td><td>2011 Peer Review Finding:

Pre-Initiator dependency is based on an incorrect interpretation of SY-B2 "No requirement to model</td><td>2011 Peer Review Plant Response:

RPS system was reviewed. Two groups of sensors, low pressurizer pressure and low low steam generator level were identified as not having diversity. As</td><td>NO IMPACT

Finding Closed - No</td></tr>
</table>

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	01		intra-system common-cause" and includes judgments that are not adequately defended. The following excerpts from the HRA Notebook demonstrate this misinterpretation and do not present any compelling justification for the judgments: Per ASME SR SY-B2, there is no requirement to model intersystem common cause failure. As miscalibration of redundant channels is a common cause failure, miscalibration between different systems need not be modeled. By considering diverse input signals to an actuation signal as "different systems", screening of signals can be accomplished based on diversity. A signal channel typically consists of a transducer, transmitter, power supply and an analog-to-digital converter that converts the input from the transmitter to an on-off signal using a bistable. Calibrations are performed on the transducer/transmitter and on the bistable. Miscalibration of either the transmitter or bistable setpoints can defeat the automatic actuation signal. For redundant channels, calibration of the transmitter can be screened out from further consideration, if signals provided by the transmitters are also used for indications in the control room. For example, steam generator level has redundant channels that are monitored closely by control room personnel during normal operation. If one or more redundant channels deviate from the rest, the operators would take notice. However, the calibration of the bistables cannot be screened out as a miscalibration may only become evident when the signal is required. For signals that are simply generated by relay contacts due to loss of voltage across the relay coil, miscalibration is deemed not to be a significant contributor to signal failure. Miscalibration is therefore not to be modeled for the signals such as loss of offsite power / 4 kV bus undervoltage. RPS should be considered a single system and	such, common cause mis-calibration errors were calculated and added to the Unit 1 and Unit 2 models for these groups of sensors. No other signals were identified which did not have diversity. Calculation MSE-EJJ-05-10, "Point Beach Nuclear Power Plant Mis-calibration Human Reliability Analysis", dated December 19, 2005 identified low pressurizer pressure, VCT Level and AFW pressure as common cause mis-calibration failures. The low pressurizer pressure was added above. The VCT Level and AFW pressure were added to the model as a result of this calculation. The values used for the common cause of these sensor groups was obtained from Calculation MSE-EJJ-05-10. The calculation has been included in Appendix A - Mis-calibration. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	**open issues from the 2010 or 2011 Peer Review**

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			screening based solely on intra-system common-cause considerations should not apply. The model includes no common-cause miscalibration or misalignment and the basis for this treatment is not adequately defended. **Screening of pre-initiators also includes a notion of diversity. The concept of diversity is not adequately developed:** The automatic actuation signals are screened on diversity. Two groups of signals which produce automatic actuation were identified. Those related to reactor protection system and those related to ESFAS. Tables A-1 and A-2 in Appendix A show the ESFAS signals as described in the ESFAS system notebook. The reactor protection system signals are outlined in Table 7.2-1 of the FSAR and all signals have been screened from further consideration based on redundancy and diversity. As described in Chapter 14 of the FSAR all events accidents analyzed require at least two diverse parameters. **Screening based on diversity such as signals that are actuated based on two separate parameters (e.g., Level OR Pressure) seems reasonable but not all signals have such diversity.**		

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
HR-D1	**Not Met** **Finding HR-D1-01**	**HR-D2 (CC-I)** **HR-D3 (CC-I)**	**2011 Peer Review Finding:** The use of screening values does not meet HR-D2. ***The values appear arbitrarily low, for screening values, and are not based on actual procedure-based assessment (i.e., a systematic process).*** While THERP data may have been used in creating the screening values, neither the THERP or ASEP methods are used. ***For example, no consideration of independent verification is presented in the analysis approach.*** SR HR-D2 allows screening (using the ASEP approach) for non-significant HEP. As a test, the BE importance was looked at and the very first pre-initiator randomly selected (HEP-AF--TY-1P29) has a RAW of 2.06.	**2011 Peer Review Plant Response:** Screening values were reset from 1E-4 to 5E-4. The model was rerun and a list of BEs showing up in the CDF cutsets at a truncation of 1E-11 was generated. The mis-positioning BEs in the list were then reviewed to see which if any were important. A mis-positioning BE was considered important if the F-V was greater than 0.005 or the RAW was greater than 2. There was one mis-positioning BE on Unit 1 which had a RAW that was slightly less than 2 and one mis-positioning BE on Unit 2 which had a RAW greater than 2. These events had a detailed ASEP analysis performed to generate a specific value for them. The value obtained was then inserted into the model and used for the quantification. Note that the mis-position event was for valve 1AF-109 on Unit 1 and 2AF-109 on Unit 2, are the same mis-positioning event. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
HR-G5	**CC-II** **Finding HR-G5-01**	**HR-E3 (CC-I)** **HR-E4 (CC-I)**	**2010 Peer Review Finding:** Talk throughs were performed for E-0, ECA 0.1, E-1.3 and E-1.4 and for risk significant operator actions (Section E.2). Simulator observation was provided for SGTR event that address timing for actions. Appendix E.4 provides simulator observations to several procedures but only provides timing information. But after a review of the risk significant operator action in the quantification notebook and Appendix E there was limited or no information on (HEP-SW--START-IE, HEP-AF--CST-FW, HEP-AF--CST—LOW). In general the only insights documented from these interviews were to support timing. ***There is little or no documentation to support the evaluation of the information that impacts the cognitive, stress levels, and information that support the THERP***. For example the time window information HEP-CCW-STDBY-IE (OPS FAILS TO ALIGN STANDBY HEAT EXCHANGE (PRE REACTOR TRIP)) is based on the High CCW temperature alarm. The limiting time should be based on high RCP bearing temp. During an operator interview the operators would trip the reactor in a shorter time window than 15 minutes to protect the RCPs. ***Without this level of detail in the document it is***	**2010 Peer Review Plant Response:** The reviewer and analyst clearly agree that time required to complete actions were based on operator talk-throughs of the procedures or simulator observations. HR-G5 does not require documentation of operator interviews to support the evaluation of the information that impacts the cognitive, stress levels, and information to support execution analysis. However, review of Appendix F by the HRA analysts showed that Appendix F, Section F.2, was inadvertently truncated. This table included additional operator interview insights related to execution on additional risk significant HFEs (As of 8/4/10). Not included in Section F.2 were 3 risk significant HFEs related to aligning the battery charger and these HFEs were re-interviewed with operations and the insights are included in the HFE analysis. The overall HEP values were not impacted by additional operator insights. HEP-125-BAT-CHG OPS FAILS TO ALIGN PWR/RELOAD TO BATT CHARGER FROM CONTROL ROOM HEP-125-COG OPS FAILS TO RECOGNIZE NEED TO PWR BATT CHARGER (COMMON COG) HEP-125-COG-REC OPS FAILS TO RECOVERY BATTERY CHARGER AFTER BATTERIES DEPLETE	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			difficult to reproduce results. ***Talk throughs and/or simulator run insights should cover information required to support the evaluation of the information that impacts the cognitive, stress levels, and information to support the THERP. At a minimum this level of detail should be provided for all risk significant operator actions.*** An example of information that would be expected to be documented and asked during an interview would, for each scenario, confirmation that the action and procedure steps are correctly performed. Document the number of people required to support the actions (impotent for local actions). Documenting information to support the information necessary to evaluation the cognitive error (clearly of the cue, front panel or back panel, etc). Document the workload during the event (Are you in multipage procedures or one, stress level, etc). Document time window estimates. If time to cue or time to undesirable state is based on T&H ask if these times are consistent with what they have seen on the simulator.	**ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	
			2011 Peer Review Finding: Note that this original finding is related to SRs HR-E3, HR-E4, and HR-G5 (HR-E3 and HR-E4 listed as CC: I by original peer review team). HR-E3 requires interviews to confirm procedure interpretation and HR-E4 requires confirmation of response models. ***Plant response to this F&O does not address HR-E3 and HR-E4. More complete operators interviews appear required. Also, the documentation appears to alternately list the Interview Appendix as Appendix E and Appendix F. This editorial issue should be corrected when additional operator interview information is added.***	**2011 Peer Review Plant Response:** Section 4.2 of the HRA Notebook, 6.0 has been rewritten to clearly identify simulator observations and operator interviews conducted to confirm the interpretation of the procedures is consistent with observations and response models are correct for scenarios modeled. Appendix E has added Section E.5, "Additional Emails with operations and plant staff to support HRA". Documentation has been revised to correctly list Appendix E and Appendix F as appropriate. Response to Finding from November 2010 stated that "Appendix F, Section F.2, was inadvertently truncated. This table included additional operator interview insights related to execution on additional risk significant HFEs (As of 8/4/10)." This should read " Appendix E, Section E.2, was inadvertently truncated. This table included additional operator interview insights related to execution on additional risk significant HFEs (As of 8/4/10)." **ALL issues identified in the 2011 Peer Review Findings were resolved in**	

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				the PRA Model.	
DA-C7	**CC-I** **Finding DA-C7-01**		**2010 Peer Review Finding:** For the Level 2 requirements, this SR states "BASE number of surveillance tests on plant surveillance requirements and actual practice. BASE number of planned maintenance activities on plant maintenance plans and actual practice. BASE number of unplanned maintenance acts on actual plant experience." Estimations were made regarding testing frequencies (see Section 2.3.3 in Data Calculation, lastbut-one paragraph). Therefore it meets CC I. Update the data analysis to include actual plant information instead of estimations.	**2010 Peer Review Plant Response:** Plant Response: In Appendix A the component for which the number of tests are stated as "Estimated" were obtained from the system engineer during the system engineer interview (SW pumps). The system engineer described actual practice of pump testing which was erroneously stated as "Estimated." This has been re-worded to properly describe the source in the "Notes" column in Appendix A table. The process of collecting test procedure data is mentioned in Section 2.3.3 Collection of Test Data. Following editorial change in Section 2.3.3 Collection of Test Data has been implemented to address the Cat-II requirement of the standard. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
			2011 Peer Review Finding: MSPI (Mitigating Systems Performance Indicator) surveillance data was used, but this is still an estimation technique (not actual) and at most slightly conservative. In Appendix A it appears that actual demands may have been used for non-MSPI equipment, but this is not described in main report.	**2011 Peer Review Plant Response:** MSPI surveillance data was not used. The MSPI Basis Document for Point Beach was used. From **Section 1.1.6** of the MSPI Basis Document "For Point Beach, the numbers of demands for Emergency AC System are based on the actual number of demands and estimated run hours from surveillance tests performed." **Section 1.3.6** "For Point Beach, the numbers of demands and run hours for Auxiliary Feedwater are based on a combination of estimates based on surveillance frequencies and on actual data from data loggers on the motor driven pumps with PMT demands and run hours removed." **Section 1.4.6** "For Point Beach, the numbers of demands and run hours for Residual Heat Removal are based on a combination of estimates based on surveillance frequencies and on actual data from data loggers on the RH pumps with PMT demands removed." **Section 1.5.6** "For Point Beach, the numbers of demands and run hours for Service Water are based on a combination of estimates based on surveillance frequencies and on actual data from data loggers on four of the six Service Water pumps with PMT demands removed." **Section 1.6.6** "For Point Beach, the numbers of demands and run hours for Component Cooling Water are based on a combination of estimates based on surveillance frequencies and on actual data obtained from Safety Monitor." **Section 1.2.6** on Safety Injection is estimated based on the number of times surveillance testing is performed and operating instructions for use. This led to 132 demands on the SI pumps used in the data analysis notebook. Subsequently, the number of SI pump demands was determined from the Safety Monitor data for the timeframe used for the data analysis notebook. There were actually 154 start demands on	

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				the SI pumps. Therefore, the data analysis notebook is conservative and no change to the model is required. To clarify that actual demand failures were used, the third paragraph of Section 2.3.3 of the Data Analysis Notebook was changed to read as follows: Plant surveillance data of 3 years was obtained from MSPI basis doc, Revision 14, September 30, 2009. This data was annualized for computing the test and maintenance unavailability due to surveillance procedural tests, actual planned maintenance activities and unplanned maintenance acts on actual plant experience at Point Beach. In cases where MSPI basis document demand data was not available, actual demands were determined from data logging devices installed on the equipment or from Safety Monitor. The component demand data is presented in Appendix A.	
DA-C8	**CC-II/III** **Finding DA-C8-01 Doc Only**		**2010 Peer Review Finding:** ***Plant-specific operational records were not used for components such as SW pumps - these were lumped together*** Assumed symmetry across the similar components - this meets the CC I in the Standard for DA-C8 ***Apply component specific data to each individual component for unavailability.***	**2010 Peer Review Plant Response:** In 6 years of the data period following are the actual observations about service water pumps: 1. There were no failures to run incidents for any of the service water pumps. 2. All the pumps were evenly swapped for running and no preferential treatment was given to any of the pumps. 3. There was only one failure to start out of the system engineer estimated 2592 starts. 4. All the Plant operators logs were studied to look for coherence and absolutely no specific operational preference were given to any pump. The plant specific operational and standby status timing of each SW pump was obtained from the system engineer. Additionally, the **running** time **of** components in normally operating systems was not imbedded in the PRA. Rather, the PRA was set up to be imported into the Safety Monitor and thus house events had been used to set the status of running and standby equipment. In response to F&Os IE-C10-01 and SC-A6-03 specific configurations with the duration for each configuration have been added to the PRA. This incorporates the plant-specific operational records. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
			2011 Peer Review Finding: **Information could not be found in DA or SW System Notebooks (Doc only)**	**2011 Peer Review Plant Response:** The purpose of collecting data is to try to estimate future performance. It is a better estimate of future unavailability by polling the data for identical	

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				components in the same system. The data should be long term averages, so the occurrence of unavailability due to failure should average out over the long term. Therefore, long term averages will continue to be used. Component specific unavailability data will not be used. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
DA-C10	**CC-I** **Finding DA-C10-01**		**2010 Peer Review Finding:** This SR states "when using surveillance test data, REVIEW the test procedure to determine whether a test should be credited for each possible failure mode. COUNT only completed tests or unplanned operational demands as success for component operation." For Level 2 - it also requires "If the component failure mode is decomposed into sub-elements (or causes) that are fully tested, then USE tests that exercise specific sub-elements in their evaluation." This is met at CCI since the first part of requirement appears to be done appropriately, ***but it does not appear that the component failure modes are decomposed into sub-elements that are fully tested.*** Review the procedures down to the sub-element level and use the information to credit tests that exercise specific sub-elements.	**2010 Peer Review Plant Response:** The Summary Assessment is not true. The review of test procedures was performed. The results of this review are shown in Appendix A of the Data Notebook. As per Capability Category III, Table-7 of the data notebook lists the actual hours of unavailability for the components as per the decomposition of the component failure mode into sub-elements that are fully tested and use tests that exercise specific sub-elements in their evaluation. In the calculation of unavailability hours for the data period it was ensured that double counting of unavailability is avoided. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
			2011 Peer Review Finding: Section 2.3,3 describes the process for evaluating test data obtained via surveillance procedures. ***It does not state that it evaluates procedure to determine if test can be credited for all possible failure modes of the component.***	**2011 Peer Review Plant Response:** Per Scientech e-mail from Lincoln Sarmanian dated 10/31/2011 @ 3:29 PM the procedures were evaluated to determine that the appropriate failure modes depending on the type of component were accounted for. The first paragraph of Section 2.3.3 was revised to read as follows (underlined text was added): *Data for the number of demands based on surveillance testing was generated through the demands stated in procedures and requirements (performance per demand) during various plant states is tabulated in Appendix A. The number of times a test procedure was required was recorded for the key components. The procedure was then reviewed to*	

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				determine the number of demands on the component for each test run. The appropriate failure modes for the type of component were accounted for in the procedure review. In addition, key components which were not being tested but did receive demands were also recorded. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
DA-C14	**Not Met** **Finding DA-C14-01**		**2010 Peer Review Finding:** The System Notebook Guidance notebook states that a specific review for possible activities which can cause the simultaneous unavailability of redundant equipment is documented in the Data Notebook. No discussion of such a review was found in the Data Notebook. Although the team confirmed that concurrent planned maintenance on redundant equipment is not allowed per plant philosophy, this is not addressed anywhere in the PRA. Because of this, T&M event combinations are showing up in dominant cutsets that are in reality not allowed, and should have been eliminated as mutually exclusive events. Add in a discussion of the plant philosophy that does not allow concurrent planned maintenance on redundant equipment - including redundant equipment in the opposite unit. Once this is complete, a review of ALL T&M events in the PRA should be performed to determine which ones are precluded from being planned concurrently, and these combinations should be added into the system notebooks and the fault tree model as mutually exclusive events.	**2010 Peer Review Plant Response:** Plant Response: All T&M events contained in the models were reviewed, along with the plant Technical Specifications. Additional combinations of T&M events were added to the MEX portion of the CAFTA fault tree. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
			2011 Peer Review Finding: ***Finding was that a discussion of concurrent maintenance was not found in the DA Notebook.***	**2011 Peer Review Plant Response:** Reviewed Real Time Safety Monitor from December 11, 2009 through December 11, 2010 for Unit 1 and Unit 2. Only concurrent maintenance found on a regular basis was battery and associated battery charger. Whenever battery D05 was OOS, the associated battery charger D07 was also OOS. When battery D06 was OOS, battery charger D08 was also OOS. When battery	

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				D105 was OOS, battery charger D107 was also OOS. When battery D106 was OOS, battery charger D108 was also OOS. The converse is not true. When a battery charger was out of service, the associated battery was aligned to the spare battery charger. Since the maintenance for the battery and associated battery charger is concurrent, they are not independent events, but the same event. To account for this the same T&M event was used for the battery and associated battery charger. This change did not affect the CDF or LERF on either unit. Section 3.3 of the Data Analysis Notebook was updated to describe the review that was performed, the findings and the effect on the model. ***ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.***	
DA-D1	**CC-II** **Finding DA-D1-01**	**DA-D3**	**2010 Peer Review Finding:** CHOOSE prior distributions as either non informative, or representative of variability in industry data. CALCULATE parameter estimates for the remaining events by using generic industry data. The issue is how the posterior distribution is calculated. The data notebook states that the generic priors are taken from NUREG/CR-6928. Those distributions are either beta distributions or gamma distributions depending on whether the failure mode is demands or time related. The parameters of the distributions are real numbers. The means for the posterior distribution are calculated in a manner consistent with the expressions presented on pages 14 and 15 of the PBNP notebook. Several cases were tested (AF-MDP, FR.>=1Hour and FS) and using the expressions on pages 14 and 15. The means calculated were higher than that presented in Table 5. Hence the updated distributions may be optimistic. NUREG/CR-6823 Handbook of Parameter Estimation for Probabilistic Risk Assessment discusses Bayesian updating of beta and gamma functions. Recalculate the posteriors using the information from that NUREG as guidance. Note the posterior parameters are easily calculated as is the mean. The percentile can be calculated from EXCEL	**2010 Peer Review Plant Response:** Plant Response: This F&O is incorrect and should NOT be a Finding or a Suggestion. As guided by the Cap Cat III realistic parameter estimates based on relevant generic and plant-specific evidence were calculated. The issue is the use of generic data parameters taken from NUREG/CR-6928. The NUREG presents the resulting generic data as both gamma distributions and Mean and ER and does not provide guidance as to how to use these or which set to use. The principal author stated that he had not considered using the results as we did that this is not incorrect. After several lengthy discussions both in-house and with the principal Author of NUREG/CR-6928, the consensus was that using the mean and error factor to generate the parameters for the prior distribution was correct and that using the provided gamma functions would yield incorrect results. This is artifact of the limits imposed in developing the gamma distributions presented in the NUREG. Thus, the approach used at Point Beach is correct. After discussions and review with FPL staff and performing the Bayesian updates in the CAFTA software package and obtaining the same results, it was decided to continue with the first approach, which is correct. That said, the differences between the 2 methods were evaluated. A new Table-5 was developed on the basis of the reviewer's recommendation and new insights observed for certain components like fire water pump. Bayesian update was used for specific characterization of the uncertainty.	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			or equivalent.	Prior distribution (characteristic parameters: alpha and beta) was obtained from NUREG/CR-6928 and posterior was calculated. The process has been stated in detail in section 3.1.1 Hardware Failure Rates. The parameter estimates for the remaining events were calculated by using generic industry data from Table-5 of NUREG/CR-6928. The results of the 2 methods were compared. The gamma approach essentially has smaller tails in the prior distribution and as such, the mean value of an update can be influenced to be higher with less uncertainty than the correct approach. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	
			2011 Peer Review Finding: Based on PBU1.rr dated October 2010, it appears that priors taken from NUREG/CR-6928 (MDP STBY FTS) incorrectly assigned to FW normal operating pump (MDP RNNING FTS). Also, value in Table 5 for FW-MDP FS is inconsistent with PBU1.rr. Agree that using NUREG/CR data distribution (e.g., beta) mean and EF as input to a lognormal for Bayesian updating has a minor effect. Suggestion, ensure that the 5.01 model, including Table 5are reviewed for consistency and the correct prior.	**2011 Peer Review Plant Response:** Table 5 and Table 6 were reviewed against NUREG/CR-6928 with changes made as appropriate. Were also checked against .rr files for Unit 1 and Unit 2. .rr files were updated to be consistent with revised Table 5 and Table 6. FW normal operating pump revised in Table 5 and .rr files for both units. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
DA-D4	**CC-1** **Finding DA-D4-01**		**2010 Peer Review Finding:** When the Bayesian approach is used to derive a distribution and mean value of a parameter, CHECK that the posterior distribution is reasonable given the relative weight of evidence provided by the prior and the plant-specific data. The team did not find evidence that the posterior distribution was checked to determine if it is reasonable given the relative weight of evidence provided by the prior and the plant-specific data. For a discussion of what is intended in the standard refer to NUREG/CR-6823 Handbook of Parameter Estimation for Probabilistic Risk Assessment. From the ASME Standard: Examples of tests to	**2010 Peer Review Plant Response:** Plant Response: Additional text added to Appendix C, Section 1.0. New text states: "Upon completion of the update process a reasonableness check is performed. Each posterior distribution is reviewed against the prior distribution and the weight of the plant specific evidence to ensure that the result of the update is reasonable." **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

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			ensure that the updating is accomplished correctly and that the generic parameter estimates are consistent with the plant-specific application include the following: (a) Confirmation that the Bayesian updating does not produce a posterior distribution with a single bin histogram (b) Examination of the cause of any unusual (e.g., multimodal) posterior distribution shapes (c) Examination of inconsistencies between the prior distribution and the plant-specific evidence to confirm that they are appropriate (d) Confirmation that the Bayesian updating algorithm provides meaningful results over the range of values being considered (e) Confirmation of the reasonableness of the posterior distribution mean value		
			2011 Peer Review Finding: This information is not contained in Appendix C or Section 1.0. Also there has to be a discussion about the comparison not just a statement that you did one.	**2011 Peer Review Plant Response:** Additional text added to Appendix C, Section 1.0. New text states: "Table 5 provides inputs where the prior was updated with plant specific data for the posterior. Upon completion of the update process a reasonableness check is performed. Each posterior distribution is reviewed against the prior distribution and the weight of the plant specific evidence to ensure that the result of the update is reasonable. The generic value, plant specific value and updated value were considered on a case by case basis. For those cases where the generic and plant specific data were close, the posterior was reviewed to ensure it was close. Where the generic and plant specific were different, the posterior was reviewed to ensure this was reflected. The balance of the data applied the generic prior as the posterior. Since the generic was applied, the posterior is reasonable and appropriate relative to the generic prior." **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
QU-D1	**Not Met** **Finding QU-D1-01**	**QU-D2 (Not Met) QU-D3 (Not Met) QU-D5 (Not Met)**	**2010 Peer Review Finding:** This SR requires a review of a sample of the significant accident sequences/cutsets sufficient to determine that the logic of the cutset or sequence is correct. The cutset review presented in the Quantification notebook is not adequate. Reviews describe the sequence that the cutset represents or list the failed equipment, but do not describe how the specific component failures in the cutset lead to the end state defined by the sequence. Since the equipment failures were not analyzed, significant cutsets exist that do not appear to make physical sense and do not reflect the as built, as operated plant. A specific example of a suspect cutset is cutset #4. The cutset is either invalid or represents a design deficiency of the plant. The cutset indicates failure of a single air handling unit while the non-safety related gas turbine generator is in maintenance leads *directly to core damage.* Review indicates that the cutset may be invalid or overly conservative due to a convolution of items: • HRA recovery rules are assuming a HRA failure since the power supplies for the cues to the event are not explicitly modeled. This is likely over conservative and skewing the results of the quantification. • The cutset may be due to the assumed alignment of the service water pumps, which are assumed to be in the most restrictive alignment for this type of event. This alignment assumption is most likely over conservative and skewing the model quantification results. A further example of a suspect cutset is cutset #12501, which includes simultaneous planned maintenance on both turbine driven AFW pumps. This condition would not be entered during plant operation, making the cutset invalid. Both of these cutsets were reviewed and determined valid in the quantification notebook.	**2010 Peer Review Plant Response:** No response provided.	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			Cutsets need to be reviewed to ensure the results make sense and reflect the as built, as operated plant. Cutsets need to be adequately described to facilitate understanding of the PRA.		
			2011 Peer Review Finding: No Plant Response. The QU notebook is set up properly to address SR-D1, D2, D3 and D5, however, this notebook including critical tables are not updated and competed yet. Based on review of new cutsets, old cutest #4 now requires failure of 2 AHUs versus 1, however, description of this cutset in Table 3.3-1 in previous QU Notebooks appears erroneous and inconsistent with actual cutset. Old cutset 12501 (TIA-005_SEQ) is lower in frequency, but procedurally the plant is currently allowed to have both TDPs unavailable for maintenance. Thus, this modeling is appropriate and the frequency of this cutset is less than 1E-7 Table 3.2-1 provides as discussion of significant event tree sequences and a discussion of the underlying logic (QU-D2 and D3). Table 3.3-5 provides a review of non significant cutsets (QU-D5 and D3)	**2011 Peer Review Plant Response:** At the time of the Peer Review for the Internal Events PRA, the Quantification Notebook was in Draft. Based on the final version of the Quantification Notebook, the tables, cutset descriptions, and cutsets were updated. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
QU-D4	**CC-I** **Finding QU-D4-01**		**2010 Peer Review Finding:** This SR requires the PRA to compare its results to those from similar plants and IDENTIFY causes for significant differences. For example: Why is LOCA a large contributor for one plant and not another? While the CDF results and initiating event contributions from several plants are compared to the results from the Point Beach PRA, there is no discussion of the causes for significant differences in those results. A discussion of the reasons for the differences is necessary to meet Category II/III Provide a discussion of the reasons for significant differences in plant results.	**2010 Peer Review Plant Response:** No response provided.	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

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			2011 Peer Review Finding: No Plant response. Section 5.4 and Tables 5.4-1 and 2 provides a high level comparison, however the description of differences in results should be enhanced (the only difference cited is the 1 hour battery life assumed for Point Beach). This is a limited description that requires more detail. For example, an explanation of why loss of 4Kv is 0.0 at Point Beach and not so at other plants.	**2011 Peer Review Plant Response:** On January 10, 2012 PRA analysts from Point Beach, Prairie Island, Kewaunee and Ginna participated in a conference call/meeting to discuss the differences in the PRA results. The insights provided by this discussion have been added to Section 5.4 of the Quantification Notebook, 11.0. Differences now included are batteries, service water header arrangement, safety injection pumps and power uprate. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
QU-D7	**Not Met** **Finding QU-D7-01**		**2010 Peer Review Finding:** This SR requires a review of the importance of components and basic events to determine that they make logical sense. No review of components or basic event importances was documented in the PRA documentation. Perform and document a review of the significant components/basic events.	**2010 Peer Review Plant Response:** No response provided.	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
			2011 Peer Review Finding: No Plant Response Alignment assumptions (e.g., SW and CCW configurations) were updated and therefore do not need to be added, however, charact erization of assumptions are all minimal or no impact is questionable and still needs improvement. For example, battery life of 1 hours is characterized as "no impact" yet in comparison with other plants (Section 5.4) this is characterized as a significant difference with other plants.	**2011 Peer Review Plant Response:** Section 5.0 of the PRA Notebook 11.0, Quantification Notebook contains a discussion on the sources of uncertainty and their impact to the PRA. In particular, battery life is discussed in Section 5.2.2.11, in which no impact is assessed because the current depletion time of 1 hour matches the existing documentation. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
QU-E4	**Not Met** **Finding QU-E4-01**	**QU-F4** **LE-F3**	**2010 Peer Review Finding:** Many of the items identified in Table C-1 are listed as not impacting because the assumption is considered conservative. The use of realistic assumptions in place of conservative assumptions would be expected to reduce the core damage frequency for many of the items identified as conservative. In	**2010 Peer Review Plant Response:** No response provided.	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer**

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			addition, some assumptions represent the modeling approach used (e.g., length of time that secondary side cooling is available using AFW). These assumptions are very conservative based on a consideration of plant design and operation. SRs QU-E1 and QU-E2 require modeling uncertainties and assumptions to be identified. SR QUE4 requires these be properly characterized. Table C-1 should be reviewed and conservative assumptions should be realistically characterized. In addition, plant configuration assumptions can have a significant impact on model results. Plant configuration assumptions should be included in Table C-1 and their impact on the overall model results assessed.		**Review**
			2011 Peer Review Finding: No Plant Response. Alignment assumptions (e.g., SW and CCW configurations) were updated and therefore do not need to be added, however, characterization of assumptions are all minimal or no impact is questionable and still needs improvement. For example, battery life of 1 hour is characterized as "no impact" yet in comparison with other plants (Section 5.4) this is characterized as a significant difference with other plants. The internal events PRA can be used for applications by resetting basic events values to the desired values through the use of a flag file. To find out the impact of flooding out a room, all the equipment and operator actions failed by the flooding in the room would be reset using a flag file to failed (TRUE). The impact of the applications on the model is application specific.	**2011 Peer Review Plant Response:** Section 5.0 of the PRA Notebook 11.0, Quantification Notebook contains a discussion on the sources of uncertainty and their impact to the PRA. In particular, battery life is discussed in Section 5.2.2.11, in which no impact is assessed because the current depletion time of 1 hour matches the existing documentation. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
QU-F5	**Not Met** **Finding QU-F5-01**	**LE-G5**	**2010 Peer Review Finding:** This SR requires documentation of limitations in the quantification process that would impact applications. The discussion of limitations in the quantification	**2010 Peer Review Plant Response:** The model was changed to address all possible configurations of the normally operating systems. The change added alignments so all pumps have T&M, are standby or running,	**NO IMPACT** **Finding Closed - No open issues from the 2010**

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			process does not appear to be adequate. There is a discussion in the quantification notebook that is limited to quantifying sequences with failure probabilities greater than 0.1. There is no discussion of quantification process items which could impact applications. For example, the model assumes certain equipment alignments in the master flag file. The assumed alignments could impact applications, and the assumed alignments should be noted in the limitations discussion so that the impact on applications can be addressed when the model is used in support of applications. Review the model and quantification process and identify process and modeling items that are unique to the Point Beach PRA quantification that an analyst needs to be aware of when supporting applications.	etc. Changes were made to the service water system, the component cooling water system, and the instrument air system. As a result of these changes there is no need to discuss the impact of the assumed alignments as these are no longer used in the model. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**or 2011 Peer Review**
			2011 Peer Review Finding: Finding LE-G5-01 is not addressed above. Also, a discussion of flag file setting and their potential impact on results, importance and applications has not been presented as requested by the original peer review.	**2011 Peer Review Plant Response:** The technical basis explaining how the operator action was subsumed was added to Section 4.0 of the Large Early Release Frequency Notebook, 12.0. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
LE-B1	**CC-II** **Finding LE-B1-01 Doc Only**		**2010 Peer Review Finding:** No credit was taken for manual actions to vent the reactor pressure vessel (post core damage) to reduce vessel pressure. Venting is ultimately credited for venting through a stuck open pressurizer PORV or safety valve when addressing an induced SGTR. However, the severe accident management guidelines call for depressurization, additionally fidelity and use of the low RCS pressure branch in the event tree. Include the action (with hardware properly accounted for) or justify not including it.	**2010 Peer Review Plant Response:** Credit for manual action to vent the reactor vessel was taken. Although not applied as a functional heading in the Containment Event Tree (Figure 4-1 of PRA 12.0), a 50% probability of early RCS depressurization, which represents manual opening of a PORV or a stuck-open PORV, was used when calculating the probabilities of PI-SGTRs and TI-SGTRs in Appendix C of PRA 12.0 (see Appendix C item # 6, listed as "APET Heading F"). This treatment is very similar to the treatment provided for early RCS depressurization in WCAP-16341-P (for which, unfortunately, Point Beach was not a participant). Generally, this WCAP is considered to represent a Category II model. However, there are three differences between the WCAP modeling and the NUREG modeling: The WCAP used a success probability of 0.9 for early RCS depressuization, based upon Engineering Judgment. A value of 0.5 is used based upon NUREG-1570 (which also used Engineering Judgment).	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

SR	Category and Finding	Other Affected SRs	PEER REVIEW FINDINGS	RESOLUTION	IMPACT ON APPLICATION
				The WCAP assumes successful early RCS depressurization prevents TI-SGTR. The NUREG-1570 model assumes that if the S/Gs are depressurized, there is still a probability of TI-SGTR even with early RCS depressurization. In the WCAP, successful early RCS depressurization potentially yields a different early containment failure probability (although both failure probabilities are approximately equal). The PB CET containment failure probabilities (i.e., CF_LOW and CF_HIGH) are assumed equal. Thus, an early RCS depressurization would not yield different containment failure results. One final comment. The NUREG-1570 Induced SGTR model contains three main branches or pathways: 1) the RCS is initially intact and may become depressurized via a number of ways, including manual depressurization (path A); 2) the RCS has a seal LOCA (path B); and 3) the RCS has a very early stuck open PORV (path C). Given the PB tube integrity, the only possibility of a TI-SGTR is for the path that contains a seal LOCA (path B). Because the RCS has a depressurization pathway, intentional depressurization is not questioned for this pathway in the NUREG-1570 model. Thus, only a PI-SGTR may be impacted by intentional depressurization (thus addressing the second bulleted modeling difference from above). A sensitivity was performed in which the successful depressurization probability was changed from 0.5 to 0.9. The PI-SGTR probability had an insignificant change (thus addressing the first bulleted modeling difference from above). Given the above discussion, the following conclusions are provided: Credit for manual action to vent the reactor vessel was taken. A sensitivity on the probability of successful early RCS depressurization was performed and the PI-SGTR probability had an insignificant change. Successful early RCS depressurization would have no impact to the TI-SGTR probability. Successful early RCS depressurization would have no impact on the early containment failure probability. Therefore, no changes were made to the Point Beach LERF Notebook. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	
			2011 Peer Review Finding: *CC-II requires review of significant accident* sequences and justification for any repairs credited. There is no evidence that this has been considered.	**2011 Peer Review Plant Response:** The technical basis explaining how the operator action was subsumed was added to Section 4.0 of the Large Early Release Frequency Notebook, 12.0. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
LE-C2	**CC-I** **Finding LE-C2-02**	**LE-C4 (CC-I)**	**2010 Peer Review Finding:** One action, HEP-CI--EOP-0-A2, which is to close the containment isolation valves given a LOCA, was included in the model. As stated in Section 5.2.2 of PRA 11.0, " MAAP analyses for break sizes larger than 6" had insufficient time available to perform the action. Therefore, this HEP is "OR"ed in the model with the Large LOCA initiating event. However, a review of the model revealed that this operator action was "AND"ed with the large LOCA initiator. Change the Gate from "AND" to "OR" and verify that the rest of the logic remains valid.	**2010 Peer Review Plant Response:** This action was reviewed in the CAFTA fault tree logic. Agree with the suggested gate change. Change gate GCI1444 from an "AND" gate to an "OR" gate. The remainder of the logic is valid. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
			2011 Peer Review Finding: Gate GCI1444 has not been changed	**2011 Peer Review Plant Response:** Changed gate GCI1444 from an "AND" gate to an "OR" gate. The change does not affect CDF since it is in the LERF fault tree, containment isolation. The delta Unit 1 LERF due to this change was 2E-12. There was no delta Unit 2 LERF due to this change. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
LE-C3	**CC-I** **Finding LE-C3-01 New**		**2011 Peer Review Finding:** Original suggestion is limited in scope and since CC-II is not obtained for SR-C9 through C12, this should have been a finding. Above response does not address CC-II requirements (e.g., need to explain that containment analysis went beyond NUREG and is CC-II and add it to the notebook if this is true). Also, the present LERF Notebook is not a complete Level 2 model. If it exists it is not available.	**2011 Peer Review Plant Response:** The LERF Analysis does meet CC-I requirements. Use of the PRA which meets CC-1 requirements is conservative.	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
LE-C9	**CC-I** **Finding LE-C9-01**	**LE-C10 (CC-I) LE-C11 (CC-I) LE-C12 (CC-I) LE-D3 (CC-I)**	**2010 Peer Review Suggestion:** Point Beach uses a unit-specific NUREG/CR-6595 CAFTA one-top model covering both CDF and LERF. The model should be expanded to address the dual unit impacts but no additional level of detail would be required. The NRC has indicated that for most applications, they are only interested in LERF. Furthermore, they have indicated that the use of a simplified NUREG/CR-6595 LERF model was	**2010 Peer Review Plant Response:** First, this is a suggestion only and there is no requirement to address this issue. Second, the Peer Review was of the Level 1 CDF and LERF Model. The issue raised suggests that A Level 2 PRA would likely be required to evaluate some issues of containment performance. This is outside the bounds of the areas to be evaluated in a Level 1 Peer Review. Additionally, it should be noted that Point Beach has a complete Level 2 PRA model, which is in the process of being updated, that is available to be used for	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			acceptable as long as it addressed plant-specific differences from the model in NUREG/CR-6595. However, for any application that directly addresses containment performance or the actual source terms and timing, a more detailed analysis approximating a Level 2 PRA would likely be required	any evaluation of containment performance for which the Level 1 LERF model is deemed insufficient. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	
			2011 Peer Review Finding: Original suggestion is limited in scope and since CC-II is not obtained for SR-C9 through C12, this should have been a finding. Above response does not address CC-II requirements (e.g., need to explain that containment analysis went beyond NUREG and is CC-II and add it to the notebook if this is true). Also, the present LERF Notebook is not a complete Level 2 model. If it exists it is not available.	**2011 Peer Review Plant Response:** The LERF Analysis does meet CC-I requirements. Use of the PRA which meets CC-1 requirements is conservative. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
LE-D5	**CC-II** **Finding LE-D5-01 Doc Only in AS**		**2010 Peer Review Finding:** The secondary side isolation analysis was performed in a conservative manner without a detailed analysis of isolation capability. For example, all steam generator tube rupture core damage sequences are conservatively assumed to lead to LERF. The analysis meets Capability Category I, but a more detailed, realistic analysis is necessary to meet Capability Category II or higher. Perform a more detailed realistic secondary side isolation analysis to meet Capability Category II or higher.	**2010 Peer Review Plant Response:** The end states of the SGTR event are GLH (SGTR, Late core damage, High pressure) and GEH (SGTR, Early core damage, High pressure), and only GEH is considered LERF (PRA 12.0, Section 3.2.3). The following SGTR GEH sequences either do not question isolation or isolation was successful, yet are considered LERF for PB: R-022: Isolation not questioned, AFW to ruptured S/G used, thus ruptured S/G not isolated. Therefore isolation is not successful. A more detailed isolation analysis not required for this sequence. R-023: Isolation not questioned, all AFW fails. A Level 2 MAAP analysis shows that this sequence results in RCS and S/G pressures rising to the point of S/G ASD and/or MSSV actuation. Therefore isolation is not successful. A more detailed isolation analysis not required for this sequence. R-026: Isolation successful, cooldown and depressurization fails. Because of the failure of cooldown and depressurization, the ruptured S/G continues to fill due to primary to secondary flow resulting in opening of the S/G ASD and/or MSSV. Therefore isolation is not successful. A more detailed isolation analysis not required for this sequence. R-031: Isolation successful, cooldown and depressurization fails. Because of the failure of cooldown and depressurization, the ruptured S/G continues to fill due to primary to secondary flow resulting in opening of the S/G ASD and/or MSSV. Therefore isolation is not successful. A more detailed isolation analysis not required for this sequence. Note that the PB SGTR emergency procedure (EOP-3) cannot prevent the	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
				MSSVs from opening, and the ruptured S/G ASD controller is set to 1050 psig. This setting does not preclude the ASD from opening under the sequence conditions described above. Thus, successful isolation does not preclude the possibility of a release from the ruptured S/G. Therefore, no changes were made to the Point Beach LERF Notebook. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	
			2011 Peer Review Finding: Agree with technical explanation, but this explanation must be added to the AS Notebook for SGTR to close this Finding.	**2011 Peer Review Plant Response:** The technical explanation was added to the end of Section 5.8.4 of the Accident Sequence Notebook. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	
LE-F1	**Not Met** **Finding LE-F1-01**		**2010 Peer Review Finding:** There were some discrepancies between Unit 1 and Unit 2 LERF results for loss of offsite power. Point Beach did identify the error but has not corrected as yet. Point Beach did provide the LERF results for both units in tables and pie charts. The pie chart for Unit 2 did not agree with the tables for ISLOCA results or SGTR results. Specifically, the table shows a LERF contribution of 9.3 % for ISLOCA but ISLOCA does not show up in the pie chart for unit 2. Also, the table shows a LERF contribution of 16.4% for Unit 2 but the pie chart for Unit 2 shows 1% Correct the known error with respect to the Loss of Offsite Power Contributions. Review the LERF results and adjust the tables and pie charts so that they are consistent with each other.	**2010 Peer Review Plant Response:** No response provided.	**NO IMPACT** **Finding Closed - No open issues from the 2010 or 2011 Peer Review**
			2011 Peer Review Finding: Errors corrected. However, it appears that S2 gate GINIT-S2 should be ORed with GSC1120 when input to Gate CET-013F.	**2011 Peer Review Plant Response:** Model was revised such that GINIT-S2 is "OR"ed with GSC1120 when input to gate CET-013F.	
LE-F3	**Not Met** **Finding**		**2010 Peer Review Finding:** Appendix A of PRA 12.0 contains a list of 25 assumptions specific to the LERF analysis but did	No - The 2011 Peer Review Finding was NOT resolved in the PRA Model. See resolution below. The documentation should be updated at the next PRA Model revision to	**–NO IMPACT** **The 2011 Peer Review Finding**

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	LE-F3-01		not include a characterization of the potential of the assumptions. Section 5.2 for PRA 11.0 discussed sensitivities and other sources of uncertainties. This section did contain one sensitivity analysis related to LERF but the selected case was not related to any of the assumptions in PSA 12.0. Appendix C of PRA 11.0 also contains a list of the assumptions with a "characterization". These did match the assumptions listed in PRA 12.0. The characterization was at best terse. The assumptions were characterized as "Realistic" or "Conservative". However, for the "conservative" assumptions, there was no discussion of the potential impact on the model or the results. Also, the one issue for which a sensitivity analysis was performed was not on the list. This is a good indication that the list is incomplete. a) Provide an assessment of potential impact on the model for the assumptions characterized as "conservative". b) Tie the LERF sensitivity case to a LERF assumption by adding a new assumption and review the LERF analyses to determine if there are any other assumptions that might impact the analysis. **2010 Peer Review Plant Response:** No response provided.	document the potential impact on the model for the identified assumptions. Include sensitivities in this assessment.	**was NOT resolved in the PRA Model. See resolution below.** The documentation should be updated at the next PRA Model revision to document the potential impact on the model for the identified assumptions. Include sensitivities in this assessment.
			2011 Peer Review Finding: No plant response yet.	**2011 Peer Review Plant Response:** No response provided.	
IFSO-A1	**Met** **Finding IFSO-A1-01**		**2011 Flooding Focused Peer Review Finding:** This SR states: For each flood area, IDENTIFY the potential sources of flooding including (a) equipment (e.g., piping, valves, pumps) located in the area that are connected to fluid systems (e.g., circulating water system, service water system, component cooling water system, feedwater system, condensate and steam systems); (b) plant internal sources of flooding (e.g., tanks or pools) located in the flood area; (c) plant external sources of flooding (e.g., reservoirs	**2011 Focused Flooding Peer Review Plant Response:** A review of all systems at Point Beach was performed to identify which systems were liquid systems. The Table in Section 7.3 was then updated to show the review of all liquid systems including justification for why they are not required to be addressed further or to indicate they were included. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2011 Peer Review**

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			or rivers) that are connected to the area through some system or structure; (d) in-leakage from other flood areas (e.g., back flow through drains, doorways, etc.) Listing of potential flood sources in Section 7.3 appears to be reasonably complete, but a couple of systems/tanks do not appear to be addressed including Reheat Steam, Extraction Steam, Fuel oil tanks. Lube oil reservoirs, Spent Fuel pools, etc. Since the Extraction Steam and Reheat Steam systems are specifically identified as potential HELB concerns in Section 7.1.2 of the report, they need to be included in the Section 7.3 analysis. These other fluid sources are not expected to result in new significant floods but are required to be identified for completeness, To meet the intent of the supporting requirement a review of all fluid systems should be performed and their presence needs to be mentioned, including a justification for why they are not required to be addressed further (e.g. insufficient volume, location of suction/discharge piping, with respect to pool level, presence of pool leak detection systems, etc.).		
IFSO-A5	**Not Met** **Finding IFSO-A5-01**		**2011 Focused Flooding Peer Review Finding:** For each source and its identified failure mechanism, IDENTIFY the characteristic of release and the capacity of the source. INCLUDE: (a) a characterization of the breach, including type (e.g., leak, rupture, spray) (b) flow rate (c) capacity of source (e.g., gallons of water) (d) the pressure and temperature of the source Section 7.3.2 of the Internal Flooding Analysis provides the details of the postulated internal flooding events, although temperature and pressure is not discussed in this section, and is not documented in	**2011 Focused Flooding Peer Review Plant Response:** The Temperature and Pressure information for each system modeled in the Flooding PRA was added to section 7.1.2 of the Flooding Notebook. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2011 Peer Review**

<table>
<tr><th>SR</th><th>Category and Finding</th><th>Other Affected SRs</th><th>PEER REVIEW FINDINGS</th><th>RESOLUTION</th><th>IMPACT ON APPLICATION</th></tr>
<tr><td></td><td></td><td></td><td>the WEFLOOD.XLS spreadsheet.

Temperature and pressure information needs to be provided to meet the requirements of the SR.</td><td></td><td></td></tr>
<tr><td>IFQU-A1</td><td>Met

Finding IFQU-A1-01</td><td>IFEV-B2 (Met)</td><td>2011 Focused Flooding Peer Review Finding:

As noted in F&O IFQU-A1-01 of the 2010 Peer Review, the process used to identify flood-induced initiating events is in the documentation, but the initiating events identified in the documentation does not always propagate properly into the flag files used for the quantification. In particular, the HEP events listed in Appendix 7.1J, Section 3.0 do not appear to have been included in the appropriate flag files.

To address this finding, the flag files should be reviewed for completeness and reflect the basis information in the documentation so that all results are complete and reproducible.</td><td>2011 Focused Flooding Peer Review Plant Response:

SR IFEV-B2 was not resolved from the 2010 Full Scope PRA Peer Review (F&O 2010 IFQU-A1-01). This was identified in the Draft Internal Flooding Focused Peer Review. This F&O stated that there is still an issue with the Flag Files matching the documentation. In this instance, Flag Files U1-AFPN.flg, U1-AFPS.flg, U2-AFPN.flg, U2-AFPS.flg and U2-FOPH.flg did not have the associated HEP listed in Appendix 7.1J, Section 3.0 set to TRUE. The associated flag files were revised and affected the results as follows:
<table>
<tr><th>Flood Area</th><th>Flag File</th><th>Peer Review CDF</th><th>Revised CDF</th><th>Change in CDF</th></tr>
<tr><td>U1 AFPN</td><td>U1-AFPN.flg</td><td>5.3977E-11</td><td>5.5843E-11</td><td>1.866E-12</td></tr>
<tr><td>U1 AFPS</td><td>U1-AFPS.flg</td><td>5.1662E-08</td><td>5.1662E-08</td><td>0.000E+00</td></tr>
<tr><td>U2 AFPN</td><td>U2-AFPN.flg</td><td>4.1403E-10</td><td>4.1403E-10</td><td>0.000E+00</td></tr>
<tr><td>U2 AFPS</td><td>U2-AFPS.flg</td><td>6.1560E-08</td><td>6.1560E-08</td><td>0.000E+00</td></tr>
<tr><td>U2 FOPH</td><td>U2-FOPH.flg</td><td>1.2410E-09</td><td>1.2410E-09</td><td>0.000E+00</td></tr>
</table>
As a result of this change, Appendix 7.1K was revised accordingly.

ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.</td><td>NO IMPACT

Finding Closed - No open issues from the 2011 Peer Review</td></tr>
<tr><td>IFQU-A6</td><td>Not Met

Finding IFQU-A6-01</td><td></td><td>2011 Focused Flooding Peer Review Finding:

F&O IFQU-A6-01 from the 2010 Peer Review identified that several internal events related HFEs were modified to support the quantification. However, the basis behind the "adjustments" to the HFEs did not appear to be justified - for example – a straight multiplier has been applied to the Internal Events HFEs instead of re-evaluating the HFE in detail. This is inappropriate since the conditions associated with</td><td>2011 Focused Flooding Peer Review Plant Response:

ASME-ANS RA-Sa-2009 IFQU-A6 has the following requirements:
For all human failure events in the internal flood scenarios, INCLUDE the following scenario specific
impacts on PSFs for control room and ex-control room actions as appropriate to the
HRA methodology being used:
(a) additional workload and stress (above that for similar sequences not caused</td><td>NO IMPACT

Finding Closed - No open issues from the 2011 Peer Review</td></tr>
</table>

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			the original equipment failures that resulted in the need for the HFE have changed, and the potential to respond to the failure is completely different. For the HFEs credited in the Internal Flooding analysis, a completely "new evaluation" of the HFEs need to be performed including an evaluation of the time available, the stress levels, and the potential that the equipment is even recoverable post flooding. Although additional information has been provided to attempt to justify the generic factors applied, this approach does not meet the requirements of this SR since it still does not include consideration of the scenario-specific impacts on the performance shaping factors which is required in order to meet this SR.	by internal floods) (b) cue availability (c) effect of flood on mitigation, required response, timing, and recovery activities (e.g., accessibility restrictions, possibility of physical harm) (d) flooding-specific job aids and training (e.g., procedures, training exercises) The Internal Flooding Analysis Notebook addresses each as follows: (a) Section 3.3 of Appendix 7.1H. The impacts of stress on operator reliability are addressed in NUREG/CR-1278 (Reference H-2) and take the form of multipliers that are applied to the nominal HEPs that are used to evaluate the subtasks of an operator action. These stress multipliers are considered to be applicable to flood-related stress and are used as the basis for quantifying the effects of flood-induced equipment failures and confusion on operator reliability. Table 20-16 of NUREG/CR-1278 (Reference H-2) provides a list of stress multipliers for step-by-step and dynamic actions over a range of different stress levels for both experienced and novice crews. These are used as the basis for the flood multipliers. Multiplier values for the Point Beach internal flooding analysis are determined by the following flow charts. The first flowchart is applicable to In-Control Room actions and the second flowchart is for Ex-Control Room actions. All Operator Actions in the internal events PRA model were reviewed and evaluated for the internal flooding analysis. For each PRA model operator action, the HRA Calculator data associated with the action was reviewed and the appropriate multiplier applied to the HEP per the flow charts above (See Tables 1 and 2). The HRA Calculator provided the internal event HEP value for each event, the location of the action, and the time available to complete the action. Additional workload and stress have been evaluated for workload and stress per NUREG/CR-1278 which is appropriate to the HRA methodology used in the Point Beach PRA. (b) Cue availability has been evaluated and is documented in Table 1 and Table 2 of Section 3.3 in Appendix 7.1H. (c) The effect of flooding on mitigation was documented in Section 3.0 of Appendix 7.1J. The table in this section lists the HFEs which were set to guaranteed failure for selected flood initiating events because of the flooding effects in the areas where these actions are performed. (d) Flooding specific job aids are provided in Attachment 2 to Appendix 7.1H. Attachment 2 to Appendix 7.1H are the detailed HEP calculations for the operator actions credited in mitigating the flood. No operator training on mitigating flooding is provided at Point Beach. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	

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SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
IFQU-A10	**Not Met** **Finding IFQU-A10-01**		**2011 Focused Flooding Peer Review Finding:** F&O IFQU-A10-01 of the 2010 Peer Review identified that although the Internal Flooding Analysis documentation contained a couple of tables that had LERF values provided in them, no discussion could be found that any review of the LERF analysis was performed to confirm the applicability of the LERF sequences. The current Internal Flooding analysis does include a review of cut sets to ensure that the cut sets make sense from a LERF perspective; however, it still does not contain a discussion of the review that was performed to determine if any NEW LERF sequences needed to be considered due to the unique impacts of a flood. Potential NEW LERF impacts could be required if the flood could cause bypass scenarios that were not previously evaluated due to multiple spurious operations, inadvertent *openings of Containment purge valves due to flood* impacts on control panels, etc. These types of potential NEW LERF impacts need to be included in the analysis, either by confirming that there are no NEW LERF sequences, or by modifying the LERF analysis as appropriate to address any NEW LERF sequences that are identified.	**2011 Focused Flooding Peer Review Plant Response:** A discussion has been added to Appendix 7.1K, "Quantification", Section 3.2 which describes the review performed to determine if any new LERF sequences needed to be considered due to the unique impacts of a flood. No additional sequences were identified. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2011 Peer Review**
IFQU-B2	**Met** **Finding IFQU-B2-01**	**IFEV-A5 (Not Met)**	**2011 Focused Flooding Peer Review Finding:** Although significant work has been done, and detailed spreadsheets are provided, there is still an inconsistency between the write-up in the front of the documentation (Section 7.4.4) and the information contained in the WEFLOOD spreadsheet printout in Appendix 7.1B and the WEFLOOD.XLS file provided to the Peer Review Team. For example, Section 7.4.4.8 states a frequency of 3.34E-05/yr for the DG1 scenario while the WEFLOOD spreadsheet shows a frequency of 3.5E-05/yr, and section 7.4.4.9 states a frequency for the DG2 scenario of 5.97E-05/yr while the WEFLOOD spreadsheet shows a frequency of 5.01E-05/yr. Note that the flag files appear to match the WEFLOOD.XLS spreadsheet. This inconsistency should be eliminated and the	**2011 Focused Flooding Peer Review Plant Response:** SR IFEV-A5 was not resolved from the 2010 Full Scope PRA Peer Review (F&O 2010 IFQU-B2-01). This was identified in the Draft Internal Flooding Focused Peer Review. This F&O stated that there is still an issue with the IF Notebook matching the electronic files, and in this case it was the WEFLOOD.xls matching Section 7.4.4.1 through 7.4.4.35. To resolve this issue in Rev. 2 of the 2011 IF Notebook, the values referenced from WEFLOOD.xls were removed and added a statement that the flooding frequency can be found in the spreadsheet WEFLOOD.xls found in Appendix 7.1C, WEFLOOD.xls. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Finding Closed - No open issues from the 2011 Peer Review**

Attachment A – Point Beach PRA Internal Events and Internal Flooding Peer Review Findings					
SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			analysis results consistent across the applications and documentation to avoid confusion and to support future updates.		
IFQU-B3	**Not Met** **Finding IFQU-B3-01**	**IFPP-B3 (Not Met) IFQU-B3 (Not Met) IFSN-B3 (Not Met) IFSO-B3 (Not Met)**	**2011 Focused Flooding Peer Review Finding:** In the 2010 Peer Review, F&O IFQU-B3-01 was written to identify that the Internal Flooding analysis did not identify some of the major conservatisms and assumptions in the analysis. This appears to remain an open item for multiple reasons. Some specific examples include: □ Although the methodology selected for estimating initiating event frequencies is valid, it does not appear that uncertainty bounds associated with the IE frequencies were determined or documented. currently mapped to the general transient initiating event (INIT-T3), but some of the floods, by definition, impact entire systems that would result in another type of initiating event - e.g. CCW pump room flood would really be a "loss of CCW" initiating event, but it is not mapped to INIT-TCC. Mapping the flood-induced initiating events in this manner is considered an assumption and needs to be identified as such. □ The analysis specifically assumes the number of pumps running and the flow rate at which they are operating. These types of assumptions can result in major impacts on the resulting analysis and need to be addressed in the Uncertainty analysis. □ The number of pumps and therefore flow rates associated with various flood scenarios are assumed, critical heights are assumed, etc. Because these assumptions have a direct impact on timing for HRA and on determining the potential consequences of a flood, they need to be captured and sensitivities performed to determine their significance. □ There is an inherent assumption that all flood events will result in a reactor trip with PCS available. In reality, this is not true since some floods would result in a loss of CCW, others would result in a loss of Instrument Air, etc. These types of assumptions need to be identified, and their potential impact on quantification and results need to be evaluated, especially for flood scenarios that have a very large contribution to either CDF or LERF.	**2011 Focused Flooding Peer Review Plant Response:** 1. Uncertainty has been added to all flooding initiating events. The following text was added to Appendix 7.1I, "Uncertainty Analysis", Section 2.3, "Flood-Induced Initiating Events". "Initiating event frequencies are assumed to have a lognormal distribution. The error factors associated with the initiating event frequencies are determined by the order of magnitude associated with the initiating event frequency. If the initiating event frequency is E-3, an error factor of 10 is used. For an initiating event frequency of E-4, an error factor of 15 is assumed. If the initiating event frequency is E-5 or lower, an error factor of 20 is applied. The application of the lognormal distributions for the data range is consistent with how the other initiating events are treated in the PRA." 2. The following text was added to Appendix 7.1I, "Uncertainty Analysis", Section 2.3, "Flood-Induced Initiating Events". "It is assumed that all flood related initiating events can be mapped to the general transient initiating event, INIT-T3. This assumption is valid even though some floods impact entire systems. This is because in those cases where the entire system is impacted, the entire system is failed by the flag file. For example, if the flooding in the PAB reaches the height of the CCW pumps, the CCW system would be lost. The loss of the CCW system is accounted for by setting the flag files associated with the scenario to fail the CCW pumps. The reactor will trip and the CCW pumps will be lost." 3. Section 3.6 was added to 7.1I which looks at the number of pumps running and the impact on the analysis. The conclusion is that this assumption does not have a major impact on the resulting analysis. 3.6 Number of Running Pumps There are three systems which are involved with submergence flooding, the only type of flooding which would be impacted by the number of pumps running. HELB, spray and jet impingement are independent of the number of pumps in service. The three systems are service water, circulating water and fire protection. Of the three systems, only the service water system has an operator action which would be affected by the number of pumps going to a runout condition. One fire protection pump at runout is larger than any of the fire protection scenario flowrates. So, whether one pump is running or two the time to submergence is unchanged. The circulating water system floods do not credit	**NO IMPACT** **Finding Closed - No open issues from the 2011 Peer Review**

Attachment A – Point Beach PRA Internal Events and Internal Flooding Peer Review Findings					
SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			□ The qualitative and quantitative screening processes involve several subjective criteria and interpretations of the Standard that are by definition, assumptions and sources of uncertainties. Since these subjective criteria impact the entire analysis, they should be considered as significant sources of uncertainties and significant assumptions.	operator actions and will not be considered further. The time to reach critical flood height can be affected by the number of pumps running if the pipe break size is large enough to accommodate all running pumps in a runout condition. For example, the maximum flow out of a service water pipe break in the cable spreading room is about 7,000 gpm which is less than the runout flow from one operating service water pump. This means the cable spreading room time to reach critical flood height is the same for one service water pump running or six. It does not create any new flooding hazards. So, submergence floods which dominate the internal flooding risk are independent of the number of service water pumps in operation. Four of the submergence flooding areas credit operator action to stop the flood before the critical flood height is reached for service water flooding. These are AFPN, U2F, DG2 and PAB. U2F does not have any service water piping large enough to cause pump runout flow and will not be considered further. AFPN does not credit operator actions for floods which would cause runout of three service water pumps and will not be considered further. The remaining two areas had the operator actions which prevent reaching critical flood height for major flooding. It was assumed that if 4, 5, or 6 pumps were running, the operator would not be able to respond before the critical flood height was reached. The operator action failure rate was changed from the value with three service water pumps running to 1.0, always failed. The initiating event frequencies calculated from this were then substituted for the existing values in the internal flooding cutset. This changed the core damage frequency on Unit 1 from 1.98190E-6 to 1.98197E-6. The difference is 7E-11 which is not significant and the number of pumps running does not significantly affect the core damage frequency.	
IFSO-A4	**Finding IFSO-A4-01**	**IFEV-A7 (Met) IFSO-A6 (Met) IFSO-B2 (Met)**	**2011 Focused Flooding Peer Review:** F&O IFSO-A4-01 from the 2010 Peer review identified that human induced flooding needed to be added to the Internal Flooding analysis. The current analysis has a very detailed evaluation of industry-related human induced flood events, and the potential for Point Beach specific human induced flood events. In the detailed evaluation, it was identified that over the last 8 years, approximately 20% of the major flood events in industry that were determined to be applicable to Point Beach were human-induced flood events. However, the conclusion was that the probability of human-induced significant flooding in power modes was judged to be	**2011 Focused Flooding Peer Review Plant Response:** Section 7.5.3 of PRA 7.1, Internal Flooding Notebook has been revised to include human induced inadvertent fire protection system actuation and maintenance induced flooding. The spreadsheet used to calculate submergence initiating event frequencies (WEFLOOD.xls) has been updated to include human induced inadvertent fire protection system actuations and maintenance induced flooding. The table was updated to show the results of the major flood events which were applicable to Point Beach. All of the major industry flooding events which were human induced and applicable to Point Beach are in the inadvertent fire protection actuation category. Section 7.5.4 was added to PRA 7.1 which discusses maintenance-induced flooding at Point Beach. The conclusion was that maintenance induced flooding will have a negligible impact on flooding because of the low probability of	**NO IMPACT** **Finding Closed - No open issues from the 2011 Peer Review**

Attachment A – Point Beach PRA Internal Events and Internal Flooding Peer Review Findings					
SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			insignificant. Since human-induced significant floods had a 20% contribution to significant flood frequency, this conclusion appears to be unjustified. Additionally, the IFSO-A4-01 F&O stated that the walkdown sheets should consider and document the potential for human-induced flooding for each flood area. Note, there is some discussion in Section 7.3.2 associated with the potential for human-induced floods in each flood area, but it is not always easy to find or understand, and it does not provide a systematic evaluation for human-induced flooding potential.	mechanical failure and the negligible probability of human failure to incorrectly position maintenance isolation boundary valves. However, maintenance induced flooding was included for 3 submergence flooding zones. Section 7.5.6 (formerly 7.5.4) provides a detailed review of action requests at Point Beach over the last 10 years looking for cases of maintenance induced flooding. None were identified which confirms the conclusion of Section 7.5.4. Regarding the second part of the finding, that walkdown sheets should consider and document the potential for human-induced flooding for each flood area, no requirement to that effect could be identified. IFSO-A4 is related to identification of flooding mechanisms and does not discuss walkdowns. IFEV-A7 says to include consideration of human-induced floods during maintenance through application of generic data. It does not discuss walkdowns. IFSO-A6 says to conduct plant walkdowns to verify the accuracy of information obtained from plant information sources and determine or verify the location of flood sources and in-leakage pathways. This was performed as part of the flooding walkdowns. However, a separate walkdown was performed to confirm the maintenance induced flooding evaluation and is documented in added Section 7.5.5. **ALL issues identified in the 2011 Peer Review Findings were resolved in the PRA Model.**	

Attachment B – Supporting Requirements That Do Not Meet Category II Requirements					
SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
AS-B7	**Not Met** **Finding AS-B7-01**		**2010 Peer Review Finding:** This element is associated with modeling time-phased dependencies (i.e., those that change as the accident progresses, due to such factors as depletion of resources, recovery of resources, and changes in loads) in the accident sequences. Examples are: (a) For SBO/LOOP sequences, key time-phased events, such as: (1) AC power recovery (2) DC battery adequacy (time-dependent discharge) (3) Environmental conditions (e.g., room cooling) for operating equipment and the control room ***Although time-phased recoveries appear to be considered at PBNP, it is not clear that they are addressed appropriately and completely. For example, in the HVAC notebook, there are several rooms that are expected to exceed the design limits for the equipment in them, but failure of HVAC to the rooms are not modeled. Additional justification for why HVAC to those rooms is not required needs to be addressed.***	**2010 Peer Review Plant Response:** The PRA model reasonably accounts for the impacts of time phased dependencies. The model has been improved in 3 areas to better reflect the impact of time phased events. First, the Power Recovery Convolution has been revised. This calculation determines the likelihood of the recovery of offsite power at the specific times that the MAAP and the RCP Seal LOCA analyses identified as being critical to the development of accident sequences. The current Convolution analyses were developed specifically for SBO (no power available from any source) and are therefore not applicable to a partial power situation such as LOOP. Additionally, the modifications to the DC modeling resolve the bulk of the cutsets in LOOP that give the appearance of being long term SBO sequences. Second, the HVAC Notebook analyses have been revised. Additional consideration was given to the available information and additional analyses were performed to quantitatively support the conclusions presented in the notebook. Third, the modeling and tagging of battery depletion and the recovery rules for restoration of power to a DC bus have been revised. The previous model had a single tag to identify a depleted bus and the HEP dependencies are cued off of this tag. This resulted in the failure of a single DC bus effectively failing all DC power (a modeling error). This has been revised such that there is a unique tag for each DC bus and the cutsets in LOOP that looked like they should be in SBO (erroneous cutsets) have been modified to correctly reflect the loss of DC at a specific bus and not the loss of all DC power. **ALL issues identified in the 2010 Peer Review Findings were resolved in the PRA Model.**	**NO IMPACT** **Removing these conservatisms may be considered in the future – this finding will remain open but does not impact the PRA results.**
			2011 Peer Review Finding: The model was improved in 3 areas to better reflect the impact of time phased dependencies as described above. HVAC notebook was updated and model includes HVAC as appropriate. ***However, the Model is still conservative because LOOP recovery for non-SBO***	**2011 Peer Review Plant Response:** In the current convolution calculation for LOSP, LOOP recovery is applied to only SBO sequences and DC battery life is not considered (i.e. **assumed to** Fail at 0 hours). This is conservative since recoveries which could be applied to reduce CDF and LERF are not applied. **Removing these conservatisms may be considered in the future –**	

Attachment B – Supporting Requirements That Do Not Meet Category II Requirements					
SR	**Category and Finding**	**Other Affected SRs**	**PEER REVIEW FINDINGS**	**RESOLUTION**	**IMPACT ON APPLICATION**
			scenarios is still neglected and the basis for this is inadequate. Also, DC life is still assumed to be 1 hour when realistic battery life is much greater (DC notebook does not mention true battery life other than full load test takes 2 ½ days). In the convolution analysis, credit is not even taken for the one battery hour. As a minimum greater detail is required to document these assumptions and their impact on the results (QU). Since the 5.00 model is being reviewed the QU results will not address additional model changes being incorporated by NEXTERA.	**this finding will remain open but does not impact the PRA results.**	
LE-F3	**Not Met** **Finding LE-F3-01**		**2010 Peer Review Finding:** Appendix A of PRA 12.0 contains a list of 25 assumptions specific to the LERF analysis but did not include a characterization of the potential of the assumptions. Section 5.2 for PRA 11.0 discussed sensitivities and other sources of uncertainties. This section did contain one sensitivity analysis related to LERF but the selected case was not related to any of the assumptions in PSA 12.0. Appendix C of PRA 11.0 also contains a list of the assumptions with a "characterization". These did match the assumptions listed in PRA 12.0. The characterization was at best terse. The assumptions were characterized as "Realistic" or "Conservative". However, for the "conservative" assumptions, there was no discussion of the potential impact on the model or the results. Also, the one issue for which a sensitivity analysis was performed was not on the list. This is a good indication that the list is incomplete. a) Provide an assessment of potential impact on the model for the assumptions characterized as "conservative". b) Tie the LERF sensitivity case to a LERF assumption by adding a new assumption and review the LERF analyses to determine if there are any other assumptions that might impact the analysis. **2010 Peer Review Plant Response:** No response provided.	No - The 2011 Peer Review Finding was NOT resolved in the PRA Model. See resolution below. The documentation should be updated at the next PRA Model revision to document the potential impact on the model for the identified assumptions. Include sensitivities in this assessment.	**–NO IMPACT** **The 2011 Peer Review Finding was NOT resolved in the PRA Model. See resolution below.** The documentation should be updated at the next PRA Model revision to document the potential impact on the model for the identified assumptions. Include sensitivities in this assessment.

Attachment B – Supporting Requirements That Do Not Meet Category II Requirements					
SR	Category and Finding	Other Affected SRs	PEER REVIEW FINDINGS	RESOLUTION	IMPACT ON APPLICATION
			2011 Peer Review Finding: No plant response yet.	**2011 Peer Review Plant Response:** No response provided.	

Attachment 3

NextEra Energy Point Peach, LLC
Point Beach Nuclear Plant

License Amendment Request No. 273
Technical Specifications
Marked-Up Pages

91 pages follow

Point Beach
Technical Specifications
Marked-Up Pages

List of Affected Pages

1.1-5	3.3.1-7	3.4.3-2	3.5.1-2	3.7.4-2	3.8.1-8	3.9.2-2
3.1.1-1	3.3.1-8	3.4.4-1	3.5.2-1	3.7.5-4	3.8.2-2	3.9.3-2
3.1.2-2	3.3.1-9	3.4.5-2	3.5.2-2	3.7.5-5	3.8.2-3	3.9.4-2
3.1.4-4	3.3.1-10	3.4.6-2	3.5.4-2	3.7.6-1	3.8.3-2	3.9.5-2
3.1.5-2	3.3.1-11	3.4.7-2	3.6.2-5	3.7.7-2	3.8.4-1	3.9.6-1
3.1.6-2	3.3.1-12	3.4.7-3	3.6.3-4	3.7.8-4	3.8.4-2	5.5-18
3.1.6-3	3.3.2-5	3.4.8-2	3.6.3-5	3.7.9-4	3.8.4-3	
3.1.8-2	3.3.3-3	3.4.9-2	3.6.4-1	3.7.10-1	3.8.6-2	
3.2.1-4	3.3.4-2	3.4.11-3	3.6.5-1	3.7.11-1	3.8.6-3	
3.2.1-5	3.3.4-3	3.4.12-4	3.6.6-2	3.7.13-1	3.8.7-2	
3.2.1-6	3.3.5-2	3.4.12-5	3.6.6-3	3.7.14-1	3.8.8-1	
3.2.2-3	3.3.6-1	3.4.13-2	3.6.7-2	3.8.1-5	3.8.9-2	
3.2.3-3	3.4.1-2	3.4.15-3	3.7.2-2	3.8.1-6	3.8.10-2	
3.2.4-4	3.4-2-1	3.4.16-2	3.7.3-2	3.8.1-7	3.9.1-1	

1.1 Definitions

RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 1800 MWt.
SHUTDOWN MARGIN (SDM)	SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. However, with all RCCAs verified fully inserted by two independent means, it is not necessary to account for a stuck RCCA in the SDM calculation; b. With any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM; and c. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal zero power design level.
SLAVE RELAY TEST	A SLAVE RELAY TEST shall consist of energizing all slave relays in the channel required for OPERABILITY and verifying the OPERABILITY of each required slave relay. The SLAVE RELAY TEST shall include a continuity check of associated required testable actuation devices. The SLAVE RELAY TEST may be performed by means of any series of sequential, overlapping, or total channel steps.
~~STAGGERED TEST BASIS~~	~~A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during n Surveillance Frequency intervals, where n is the total number of systems, subsystems, channels, or other designated components in the associated function.~~
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 SHUTDOWN MARGIN (SDM)

LCO 3.1.1 SDM shall be within the limits provided in the COLR.

APPLICABILITY: MODE 2 with $k_{eff} < 1.0$,
MODES 3, 4, and 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.1.1	Verify SDM to be within limits.	~~24 hours~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.2.1	----------NOTE---------- The predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 effective full power days (EFPD) after each fuel loading. ----------	
	Verify measured core reactivity is within ± 1% Δk/k of predicted values.	Once prior to entering MODE 1 after each refueling AND -------NOTE------ Only required after 60 EFPD ---------- In accordance with the Surveillance Frequency Control Program ~~31 EFPD thereafter~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify individual rod positions are within the following alignment limits: a. ± 18 steps of demanded position (as allowed by Table 3.1.4-1) in MODE 1 > 85 percent RTP when bank demand position is < 215 steps; AND b. ± 24 steps of demanded position (as allowed by Table 3.1.4-2) in MODE 1 > 85 percent RTP when bank demand position is ≥ 215 steps; AND c. ± 24 steps of demanded position in MODE 1 ≤ 85 percent RTP or in MODE 2.	~~12 hours~~ In accordance with the Surveillance Frequency Control Program
SR 3.1.4.2	Verify rod freedom of movement (trippability) by moving each rod not fully inserted in the core ≥ 10 steps in either direction.	~~92 days~~
SR 3.1.4.3	Verify rod drop time of each rod, from the fully withdrawn position, is ≤ 2.2 seconds from the beginning of decay of stationary gripper coil voltage to dashpot entry, with: a. T_{avg} ≥ 500°F; and b. All reactor coolant pumps operating.	Prior to reactor criticality after each removal of the reactor head

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each shutdown bank is within the limits specified in the COLR.	~~12 hours~~

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Control bank sequence or overlap limits not met.	B.1.1	Verify SDM to be within the limits provided in the COLR.	1 hour
		OR	
	B.1.2	Initiate boration to restore SDM to within limit.	1 hour
	AND		
	B.2	Restore control bank sequence and overlap to within limits.	2 hours
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 2 with $k_{eff} < 1.0$.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify estimated critical control bank position is within the limits specified in the COLR.	Within 4 hours prior to achieving criticality
SR 3.1.6.2	Verify each control bank insertion is within the limits specified in the COLR.	~~12 hours~~

(continued)

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.6.3	Verify sequence and overlap limits specified in the COLR are met for control banks not fully withdrawn from the core.	~~12 hours~~

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. RCS lowest loop average temperature not within limit.	C.1 Restore RCS lowest loop average temperature to within limit.	15 minutes
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	Verify the RCS lowest loop average temperature is ≥ 530°F.	~~30 minutes~~
SR 3.1.8.2	Verify THERMAL POWER is ≤ 5% RTP.	~~30 minutes~~
SR 3.1.8.3	Verify SDM to be within the limits provided in the COLR.	~~24 hours~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

----------NOTE----------
During power escalation at the beginning of each cycle, THERMAL POWER may be increased until an equilibrium power level has been achieved, at which a power distribution map is obtained.

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify $F_Q^C(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP AND Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F_Q^C(Z)$ was last verified AND ~~31 EFPD thereafter~~

In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.1.2	----------NOTE---------- If $F^W_Q(Z)$ measurements indicate that the maximum over z $\left[\frac{F^C_Q(Z)}{K(Z)} \right]$ has increased since the previous evaluation of $F^C_Q(Z)$: a. Increase $F^W_Q(Z)$ by the greater of a factor of 1.02 or by an appropriate factor specified in the COLR and reverify $F^W_Q(Z)$ is within limits; or b. Repeat SR 3.2.1.2 once per 7 EFPD until either a. above is met, or two successive flux maps indicate that the maximum over z $\left[\frac{F^C_Q(Z)}{K(Z)} \right]$ has not increased. ----------	
	Verify $F^W_Q(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> (continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.1.2 (continued) In accordance with the Surveillance Frequency Control Program	Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F^W_Q(Z)$ was last verified. AND ~~31 EFPD thereafter~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify $F^N_{\Delta H}$ is within limits specified in the COLR.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP AND ~~31 EFPD thereafter~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.2.3.1	Verify AFD within limits for each OPERABLE excore channel.	~~7 days~~
SR 3.2.3.2	Update target flux difference.	Once within 31 EFPD after each refueling AND ~~31 EFPD thereafter~~
SR 3.2.3.3	----------NOTE---------- The initial target flux difference after each refueling may be determined for design predictions. ---------- Determine, by measurement, the target flux difference.	Once within 31 EFPD after each refueling AND ~~92 EFPD thereafter~~

In accordance with the Surveillance Frequency Control Program

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.4.1	----------NOTES---------- 1. With input from one Power Range Neutron Flux channel inoperable and THERMAL POWER ≤ 75% RTP, the remaining three power range channels can be used for calculating QPTR. 2. SR 3.2.4.2 may be performed in lieu of this Surveillance. ---------- Verify QPTR is within limit by calculation.	~~7 days~~
SR 3.2.4.2	----------NOTE---------- Not required to be performed until 12 hours after input from one or more Power Range Neutron Flux channels are inoperable with THERMAL POWER > 75% RTP. ---------- Verify QPTR is within limit using the movable incore detectors.	~~12 hours~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.1-1 to determine which SRs apply for each RPS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	~~12 hours~~
SR 3.3.1.2	----------NOTES---------- 1. Adjust NIS channel if absolute difference is > 2%. 2. Not required to be performed until 12 hours after THERMAL POWER is ≥ 15% RTP. --- Compare results of calorimetric heat balance calculation to Nuclear Instrumentation System (NIS) channel output.	~~24 hours~~
SR 3.3.1.3	----------NOTES---------- 1. Adjust NIS channel if absolute difference is ≥ 3%. 2. Not required to be performed until 24 hours after THERMAL POWER is ≥ 50% RTP. --- Compare results of the incore detector measurements to NIS AFD.	~~31 effective full power days (EFPD)~~

In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.4	----------NOTE---------- This Surveillance must be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. ---------- Perform TADOT.	~~31 days on a STAGGERED TEST BASIS~~
SR 3.3.1.5	----------NOTES---------- 1. Not required to be performed for the Source Range Neutron Flux Trip Function until 8 hours after power is below P-6. 2. Not required to be performed for the RCP Breaker Position (Two Loops), Reactor Coolant Flow — Low (Two Loops) and Underfrequency Bus A01 and A02 Trip Functions and the P-6, P-7, P-8, P-9 and P-10 Interlocks. ---------- Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program ~~31 days on a STAGGERED TEST BASIS~~
SR 3.3.1.6	----------NOTE---------- Not required to be performed until 24 hours after THERMAL POWER is ≥ 50% RTP. ---------- Calibrate excore channels to agree with incore detector measurements.	~~92 EFPD~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.7	----------NOTE---------- Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. ---------- Perform COT.	~~92 days~~

(continued)

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.8	----------NOTE---------- This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. ---------- Perform COT.	-------NOTE------- Only required when not performed within previous 92 days ---------- Prior to reactor startup AND Four hours after reducing power below P-10 for power and intermediate range instrumentation AND Four hours after reducing power below P-6 for source range instrumentation AND ~~Every 92 days thereafter~~

In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.9	Perform TADOT.	~~31 days~~
SR 3.3.1.10	----------NOTE---------- This Surveillance shall include verification that the time delays are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	~~18 months~~
SR 3.3.1.11	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	~~18 months~~
SR 3.3.1.12	Perform COT.	~~18 months~~
SR 3.3.1.13	Perform TADOT.	~~18 months~~
SR 3.3.1.14	Perform TADOT.	Prior to exceeding the P-9 interlock whenever the unit has been in MODE 3, if not performed within previous 31 days.

In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.15	----------NOTE---------- This Surveillance must be performed on the RCP Breaker Position (Two Loop), Reactor Coolant Flow - Low (Two Loop) and Underfrequency Bus A01 and A02 Trip Functions and the P-6 , P-7, P-8, P-9 and P-10 Interlocks. ---------- Perform ACTUATION LOGIC TEST.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	~~12 hours~~
SR 3.3.2.2	----------NOTE---------- The continuity check may be excluded. ---------- Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program ~~31 days on a STAGGERED TEST BASIS~~
SR 3.3.2.3	Perform COT.	~~92 days~~
SR 3.3.2.4	Perform MASTER RELAY TEST.	~~18 months~~
SR 3.3.2.5	Perform SLAVE RELAY TEST.	~~18 months~~
SR 3.3.2.6	Perform TADOT.	~~31 days~~
SR 3.3.2.7	Perform TADOT.	~~18 months~~
SR 3.3.2.8	----------NOTE---------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	~~18 months~~

SURVEILLANCE REQUIREMENTS

----------NOTE----------
SR 3.3.3.1 applies to each PAM instrumentation Function in Table 3.3.3-1. SR 3.3.3.2 applies to each PAM instrumentation Function in Table 3.3.3-1, except Function 12. SR 3.3.3.3 applies to Function 12 only.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	~~31 days~~
SR 3.3.3.2	----------NOTE---------- CHANNEL CALIBRATION of Containment Area Radiation (High Range) detectors shall consist of verification of a response to a source. ---------- Perform CHANNEL CALIBRATION.	~~18 months~~
SR 3.3.3.3	Perform TADOT.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time of Condition A for 4.16 kV Functions or Condition B not met.	C.1	Enter applicable Condition(s) and Required Action(s) for the associated standby emergency power source made inoperable by LOP DG start instrumentation.	Immediately
D. Two or more 480 V loss of voltage channels per bus inoperable.	D.1	Restore all but one channel to OPERABLE status.	1 hour
E. Required Action and associated Completion Time of Condition A for 480 V loss of voltage Function or Condition D not met.	E.1	Be in MODE 3.	6 hours
	AND		
	E.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.1	Perform CHANNEL CHECK.	~~12 hours~~
SR 3.3.4.2	Perform TADOT.	~~31 days~~

(continued)

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.3	Perform CHANNEL CALIBRATION with Allowable Value as follows: a. 4.16 kV loss of voltage Allowable Value ≥ 3156 V with a time delay of ≥ 1.8 seconds and ≤ 2.3 seconds (Bus Loss of Voltage Relay) and ≥ 1.95 seconds and ≤ 3.55 seconds (EDG Breaker Close Delay Relay). b. 4.16 kV degraded voltage Allowable Value ≥ 3937 V with a time delay of < 5.68 seconds (Bus Degraded Voltage Relay) and < 39.14 seconds (Bus Time Delay Relay). c. 480 V loss of voltage Allowable Value 256 V ± 3% with a time delay of ≥ 1.15 seconds and ≤ 1.6 seconds.	~~18 months~~ In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Be in MODE 3. AND B.3 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.5-1 to determine which SRs apply for each CREFS Actuation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	Perform CHANNEL CHECK.	~~12 hours~~
SR 3.3.5.2	Perform COT.	~~92 days~~
SR 3.3.5.3	Perform CHANNEL CALIBRATION.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.6 Boron Dilution Alarm

LCO 3.3.6 Boron Dilution Alarm shall be OPERABLE.

APPLICABILITY: MODE 5.

ACTIONS

CONDITION	REQUIRED ACTIONS	COMPLETION TIME
A. Boron Dilution Alarm inoperable.	A.1 Close unborated water source isolation valve(s).	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.3.6.1 Perform TADOT.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is greater than or equal to the limits specified in the COLR.	~~12 hours~~
SR 3.4.1.2	Verify RCS average temperature is within the limits specified in the COLR.	~~12 hours~~
SR 3.4.1.3	----------NOTE---------- Not required to be performed until 24 hours after ≥ 90% RTP. ---------- Verify by precision heat balance that RCS total flow rate is ≥ 178,000 gpm and greater than or equal to the limit specified in the COLR.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Minimum Temperature for Criticality

LCO 3.4.2 Each RCS loop average temperature (T_{avg}) shall be ≥ 540°F.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. T_{avg} in one or more RCS loops not within limit.	A.1 Be in MODE 2 with k_{eff} < 1.0.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.2.1 Verify RCS T_{avg} in each loop ≥ 540°F.	~~12 hours~~

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ----------NOTE---------- Required Action C.2 shall be completed whenever this Condition is entered. ---------- Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1 Initiate action to restore parameter(s) to within limits.	Immediately
	AND	
	C.2 Determine RCS is acceptable for continued operation.	Prior to entering MODE 4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	----------NOTE---------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing with $k_{eff} < 1.0$. ----------	
	Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	~~30 minutes~~

In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops — MODES 1 and 2

LCO 3.4.4 Two RCS loops shall be OPERABLE and in operation.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of LCO not met.	A.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.4.1 Verify each RCS loop is in operation.	~~12 hours~~ In accordance with the Surveillance Frequency Control Program

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Two RCS loops inoperable. OR No RCS loop in operation.	C.1	Place the Rod Control System in a condition incapable of rod withdrawal.	Immediately
	AND		
	C.2	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	C.3	Initiate action to restore one RCS loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify one RCS loop is in operation.	~~12 hours~~
SR 3.4.5.2	Verify steam generator secondary side water levels are ≥ 35% narrow range for required RCS loops.	~~12 hours~~
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required RHR loop inoperable. AND Two required RCS loops inoperable.	B.1 Be in MODE 5.	24 hours
C. Required RCS or RHR loops inoperable. OR No RCS or RHR loop in operation.	C.1 Suspend all operations involving a reduction of RCS boron concentration. AND C.2 Initiate action to restore one loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	~~12 hours~~
SR 3.4.6.2	Verify SG secondary side water levels are ≥ 35% narrow range for required RCS loops.	~~12 hours~~
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable. AND Required SG secondary side water level not within limits.	A.1 Initiate action to restore a second RHR loop to OPERABLE status. OR A.2 Initiate action to restore required SG secondary side water level to within limit.	Immediately Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend all operations involving a reduction of RCS boron concentration. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	~~12 hours~~
SR 3.4.7.2	Verify SG secondary side water level is ≥ 35% narrow range in the required SG.	~~12 hours~~ *

(continued)

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend all operations involving reduction in RCS boron concentration. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify one RHR loop is in operation.	~~12 hours~~
SR 3.4.8.2	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ 52% in MODE 1 OR ≤ 88% in MODES 2 and 3.	~~12 hours~~
SR 3.4.9.2	Verify capacity of required pressurizer heaters is ≥ 100 kW.	~~92 days~~

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Two block valves inoperable.	----------NOTE---------- Required Action F.1 does not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2 ----------	
	F.1 Restore one block valve to OPERABLE status.	2 hours
G. Required Action and associated Completion Time of Condition F not met.	G.1 Be in MODE 3.	6 hours
	AND	
	G.2 Reduce T_{avg} to < 500°F.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	----------NOTE---------- Not required to be met with block valve closed in accordance with the Required Action of Condition B or E. ----------	
	Perform a complete cycle of each block valve.	~~92 days~~
SR 3.4.11.2	Perform a complete cycle of each PORV.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.12.1	Verify a maximum of one SI pump is capable of injecting into the RCS.	~~12 hours~~
SR 3.4.12.2	----------NOTE---------- Only required when accumulator pressure is ≥ the maximum RCS pressure for existing cold leg temperature allowed by the P/T limit curves provided in the PTLR. ---------- Verify each accumulator is isolated.	In accordance with the Surveillance Frequency Control Program ~~12 hours~~
SR 3.4.12.3	----------NOTE---------- Only required to be performed when complying with LCO 3.4.12.c.2. ---------- Verify required RCS vent path with venting capability equivalent to or greater than a PORV.	~~12 hours~~ for unlocked open vent valve(s) AND ~~31 days~~ for other vent path(s)
SR 3.4.12.4	Verify required trains of LTOP armed.	~~72 hours~~
SR 3.4.12.5	Perform a COT on each required PORV, excluding actuation.	~~31 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.6	Perform CHANNEL CALIBRATION for each required PORV actuation channel.	~~18 months~~
SR 3.4.12.7	Perform a complete cycle of each required PORV solenoid air control valve and check valve on the nitrogen gas bottles.	~~18 months~~
SR 3.4.12.8	Perform a complete cycle of each required PORV.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	----------NOTES---------- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE. ---------- Verify RCS Operational LEAKAGE is within limits by performance of RCS water inventory balance.	~~72 hours~~
SR 3.4.13.2	----------NOTE---------- Not required to be performed until 12 hours after establishment of steady state operation. ---------- Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG.	~~72 hours~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.15.1	Perform CHANNEL CHECK of the required containment atmosphere radioactivity monitor.	~~12 hours~~
SR 3.4.15.2	Perform CHANNEL CALIBRATION of the required containment sump level alarm.	~~18 months~~
SR 3.4.15.3	Perform CHANNEL CALIBRATION of the required containment atmosphere radioactivity monitor.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met. OR DOSE EQUIVALENT I-131 >50 μCi/gm.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	----------NOTE---------- Only required to be performed in MODE 1. ---------- Verify reactor coolant DOSE EQUIVALENT Xe-133 Specific Activity ≤ 300 μCi/gm.	~~7 days~~
SR 3.4.16.2	----------NOTE---------- Only required to be performed in MODE 1. ---------- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ≤ 0.5 μCi/gm.	~~14 days~~ AND Between 2 and 6 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify each accumulator isolation valve is fully open.	~~12 hours~~
SR 3.5.1.2	Verify borated water volume in each accumulator is ≥ 1100 ft^3 and ≤ 1136 ft^3.	~~12 hours~~
SR 3.5.1.3	Verify nitrogen cover pressure in each accumulator is ≥ 700 psig and ≤ 800 psig.	~~12 hours~~
SR 3.5.1.4	Verify boron concentration in each accumulator is ≥ 2700 ppm and ≤ 3100 ppm.	~~31 days~~ * AND ------NOTE------ Only required to be performed for affected accumulators ---------- Once within 24 hours after each solution volume increase of ≥ 5% of indicated level that is not the result of addition from the refueling water storage tank with boron concentration ≥ 2700 ppm and ≤ 3100 ppm *
SR 3.5.1.5	Verify power is removed from each accumulator isolation valve operator when RCS pressure is > 1000 psig.	~~31 days~~

In accordance with the Surveillance Frequency Control Program

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS – Operating

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

----------NOTE----------
In MODE 3, both safety injection (SI) pump flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One ECCS train inoperable.	A.1	Restore train to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify each ECCS manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	~~31 days~~
SR 3.5.2.2	Verify ECCS piping is full of water.	~~31 days~~

In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.3	Verify each ECCS pump's developed head at the test flow point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.5.2.4	Verify each ECCS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	~~18 months~~
SR 3.5.2.5	Verify each ECCS pump starts automatically on an actual or simulated actuation signal.	~~18 months~~
SR 3.5.2.6	Verify, by visual inspection, each ECCS train containment sump suction inlet is not restricted by debris and the suction inlet debris screens show no evidence of structural distress or abnormal corrosion.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.1	Verify RWST borated water temperature is ≥ 42.5°F and ≤ 97.5°F.	~~24 hours~~
SR 3.5.4.2	Verify RWST borated water volume is ≥ 275,000 gallons.	~~7 days~~
SR 3.5.4.3	Verify RWST boron concentration is ≥ 2800 ppm and ≤ 3200 ppm.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1	----------NOTES---------- 1. An inoperable air lock bulkhead does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1. ---------- Perform required air lock leakage rate testing in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.2.2	Verify only one bulkhead door and its associated equalizing valve in the air lock can be opened at a time.	~~24 months~~

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1	Deleted	
SR 3.6.3.2	----------NOTE---------- Valves and blind flanges in high radiation areas may be verified by use of administrative controls. ---------- Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	~~31 days~~

(continued)

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.3	----------NOTE---------- Valves and blind flanges in high radiation areas may be verified by use of administrative means. ---------- Verify each containment isolation manual valve and blind flange that is located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days
SR 3.6.3.4	Verify the isolation time of each automatic power operated containment isolation valve is within Inservice Testing Program limits.	In accordance with the Inservice Testing Program
SR 3.6.3.5	Verify each automatic containment isolation valve that is not locked, sealed or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.4 Containment Pressure

LCO 3.6.4 Containment pressure shall be ≥ -1.0 psig and ≤ +1.0 psig.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment pressure not within limits.	A.1 Restore containment pressure to within limits.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1	Verify containment pressure is within limits.	~~12 hours~~

In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.5 Containment Air Temperature

LCO 3.6.5 Containment average air temperature shall be:

a. ≤ 116.3°F based on three averaged temperature channels,

b. ≤ 115.7°F based on two averaged temperature channels, or

c. ≤ 112.5°F based on a single temperature channel.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Containment average air temperature not within limit.	A.1	Restore containment average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.5.1	Verify containment average air temperature is within limit.	~~24 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One required accident fan cooler unit service water outlet valve inoperable.	D.1 Restore required accident fan cooler unit outlet valve to OPERABLE status.	72 hours AND 144 hours from discovery of failure to meet the LCO
E. Required Action and associated Completion Time of Condition C or D not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.6.1	Verify each containment spray manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	~~31 days~~
SR 3.6.6.2	Operate each containment cooling accident fan.	~~31 days~~

(continued)

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.6.3	Verify each containment fan cooler unit can achieve a cooling water flow rate within design limits with a fan cooler service water outlet valve open.	~~31 days~~
SR 3.6.6.4	Verify each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.6.6.5	Verify each automatic containment spray and containment fan cooler unit service water outlet valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	~~18 months~~
SR 3.6.6.6	Verify each containment spray pump starts automatically on an actual or simulated actuation signal.	~~18 months~~
SR 3.6.6.7	Verify each containment fan cooler unit accident fan starts automatically on an actual or simulated actuation signal.	~~18 months~~
SR 3.6.6.8	Verify proper operation of the accident fan cooler unit backdraft dampers.	~~18 months~~
SR 3.6.6.9	Verify each spray nozzle is unobstructed.	~~10 years~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.7.1	Verify each spray additive manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	~~31 days~~
SR 3.6.7.2	Verify spray additive tank solution volume is ≥ 43%.	~~184 days~~
SR 3.6.7.3	Verify spray additive tank NaOH solution concentration is ≥ 30% and ≤ 33% by weight.	~~184 days~~
SR 3.6.7.4	Verify each spray additive automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. (continued)	C.3	Verify MSIV and non-return check valve in the affected flowpath are closed and the MSIV is de-activated.	Once per 7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	----------NOTE---------- Only required to be performed in MODE 1. ---------- Verify closure time of each MSIV is within limits.	In accordance with the Inservice Testing Program
SR 3.7.2.2	----------NOTE---------- Only required to be performed in MODE 1. ---------- Verify each MSIV actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program ~~18 months~~
SR 3.7.2.3	Verify each main steam non-return check valve can close.	In accordance with the Inservice Testing Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Two valves in the same flowpath inoperable.	D.1	Isolate affected flow path	8 hours
E. Required Action and associated Completion Time not met.	E.1	Be in MODE 3.	6 hours
	AND		
	E.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	Verify each MFIV, MFRV, and MFRV bypass valve, actuate to the isolation position on an actual or simulated actuation signal.	~~18 months~~
SR 3.7.3.2	Verify each MFIV, MFRV, and MFRV Bypass Valve isolation time is within limits.	In accordance with the Inservice Testing Program

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Verify one complete manual cycle of each ADV.	~~18 months~~
SR 3.7.4.2	Verify one complete manual cycle of each ADV block valve.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	----------NOTE---------- AFW pump system(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the AFW mode of operation. ---------- Verify each AFW manual, power operated, and automatic valve in each water flow path, and in both steam supply flow paths to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program ~~31 days~~
SR 3.7.5.2	----------NOTE---------- Not required to be performed for the turbine driven AFW pump until 24 hours after THERMAL POWER exceeds 2% RTP. ---------- Verify the developed head of each required AFW pump at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.7.5.3	----------NOTE---------- AFW pump system(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the AFW mode of operation. ---------- Verify each AFW automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program ~~18 months~~

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.4	----------NOTES---------- 1. Not required to be performed for the turbine driven AFW pump until 24 hours after ≥ 1000 psig in the steam generator. 2. AFW pump system(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the AFW mode of operation. ---------- Verify each AFW pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program ~~18 months~~
SR 3.7.5.5	Verify proper alignment of the required AFW flow paths by verifying flow from the condensate storage tank to each steam generator supplied by the respective AFW pump system.	Prior to THERMAL POWER exceeding 2% RTP whenever unit has been in MODE 5, MODE 6, or defueled for a cumulative period of > 30 days

3.7 PLANT SYSTEMS

3.7.6 Condensate Storage Tank (CST)

LCO 3.7.6 The CST shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. CST inoperable.	A.1	Restore CST to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 4, without reliance on steam generator for heat removal.	18 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1.A	Verify the CST level is ≥ 21,150 gallons. (2 CSTs either cross-tied or individually aligned)	~~12 hours~~
OR		
SR 3.7.6.1.B	Verify the CST level is ≥ 35,837 gallons. (1 CST supplying two units)	In accordance with the Surveillance Frequency Control Program
OR		
SR 3.7.6.1.C	Verify the CST level is ≥ 14,100 gallons. (2 CSTs supplying one unit)	

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	----------NOTE---------- Isolation of CC flow to individual components does not render the CC System inoperable. ---------- Verify each CC manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	~~31 days~~

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Required Action and associated Completion Time not met.	H.1 Be in MODE 3. AND H.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	----------NOTE---------- Isolation of SW flow to individual components does not render the SW System inoperable. ---------- Verify each SW manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program ~~31 days~~
SR 3.7.8.2	Verify each required SW automatic non-essential-SW-load isolation valve that is not locked, sealed, or otherwise secured in the closed position, actuates to the closed position on an actual or simulated actuation signal.	~~18 months~~
SR 3.7.8.3	Verify each SW pump starts automatically on an actual or simulated actuation signal.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.9.1	Operate the CREFS for ≥ 15 minutes.	~~31 days~~
SR 3.7.9.2	Perform required CREFS filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.7.9.3	Verify each CREFS emergency and recirculation fan actuates on an actual or simulated actuation signal.	~~18 months~~
SR 3.7.9.4	Verify each CREFS automatic damper in the emergency mode flow path actuates to the correct position on an actual or simulated actuation signal.	~~18 months~~
SR 3.7.9.5	Verify CREFS manual start capability and alignment.	~~18 months~~
SR 3.7.9.6	Perform required CRE unfiltered air inleakage testing in accordance with the Control Room Envelope Habitability Program.	In accordance with the Control Room Envelope Habitability Program

In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.10 Fuel Storage Pool Water Level

LCO 3.7.10 The fuel storage pool water level shall be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: During movement of irradiated fuel assemblies in the fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel storage pool water level not within limit.	A.1 ----------NOTE---------- LCO 3.0.3 is not applicable. ---------- Suspend movement of irradiated fuel assemblies in the fuel storage pool.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10.1	Verify the fuel storage pool water level is ≥ 23 ft above the top of the irradiated fuel assemblies seated in the storage racks.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.11 Fuel Storage Pool Boron Concentration

LCO 3.7.11 The fuel storage pool boron concentration shall be ≥ 2100 ppm.

APPLICABILITY: When fuel assemblies are stored in the spent fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel storage pool boron concentration not within limit.	----------NOTE---------- LCO 3.0.3 is not applicable. ----------	
	A.1 Suspend movement of fuel assemblies in the fuel storage pool.	Immediately
	AND	
	A.2 Initiate action to restore fuel storage pool boron concentration to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.11.1	Verify the fuel storage pool boron concentration is within limit.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.13 Secondary Specific Activity

LCO 3.7.13 The specific activity of the secondary coolant shall be ≤ 0.1 μCi/gm DOSE EQUIVALENT I-131.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Specific activity not within limit.	A.1 Be in MODE 3.	6 hours
	AND	
	A.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.13.1	Verify the specific activity of the secondary coolant is ≤ 0.1 μCi/gm DOSE EQUIVALENT I-131.	~~31 days~~

In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.14 Primary Auxiliary Building Ventilation (VNPAB)

LCO 3.7.14 VNPAB shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. VNPAB inoperable.	A.1 Restore VNPAB to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE		FREQUENCY
SR 3.7.14.1	Operate the VNPAB filter and stack fans for ≥ 15 minutes. Verify the associated low flow lights for filter fans and for stack fans are not lit.	~~31 days~~
SR 3.7.14.2	Verify the VNPAB system can maintain a PAB pressure less than atmospheric pressure and less than turbine building pressure.	~~18 months~~
SR 3.7.14.3	Verify VNPAB manual start capability and alignment.	~~18 months~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Required Action and associated Completion Time not met.	H.1 Be in MODE 3. AND H.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	~~7 days~~
SR 3.8.1.2	----------NOTES---------- 1. All standby emergency power source starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 2. A modified standby emergency power source start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. ---------- Verify each standby emergency power source starts from standby conditions and achieves rated voltage and frequency.	In accordance with the Surveillance Frequency Control Program ~~31 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	----------NOTES---------- 1. Standby emergency power source loadings may include gradual loading. 2. Momentary transients outside the load range do not invalidate this test. 3. This SR shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2. ---------- Verify each standby emergency power source is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 2500 kW and ≤ 2850 kW.	~~31 days~~
SR 3.8.1.4	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank to the day tank.	~~31 days~~

(continued)

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.5	----------NOTE---------- This surveillance shall not normally be performed with the associated unit in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. ---------- Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ESF actuation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. Standby emergency power source auto-starts from standby condition and: 1. energizes permanently connected loads, 2. energizes auto-connected emergency loads through load logic and sequencer, 3. achieves steady state voltage within limits, 4. achieves steady state frequency within limits, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	~~18 months~~ In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	Verify each standby emergency power source: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	~~18 months~~
SR 3.8.1.7	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. 3. If performed with the standby emergency power source synchronized with offsite power, it shall be performed at a power factor ≤ 0.87. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition, the power factor shall be maintained as close to the limit as practicable. ---------- Verify each standby emergency power source operates for ≥ 24 hours at ≥ 2850 kW (G01/G02), ≥ 2848 kW (G03/04).	In accordance with the Surveillance Frequency Control Program ~~18 months~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required standby emergency power source inoperable.	B.1 Declare affected required feature(s) with no standby emergency power source available inoperable.	Immediately
	AND	
	B.2 Initiate action to restore required standby emergency power source to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.2.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	~~7 days~~
SR 3.8.2.2	----------NOTE---------- All standby emergency power source starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. ---------- Verify each required standby emergency power source starts from standby conditions and achieves rated voltage and frequency.	In accordance with the Surveillance Frequency Control Program ~~31 days~~
SR 3.8.2.3	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank to the day tank.	~~31 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.2.4	----------NOTE---------- The following SR is not required to be performed if it is not met solely due to an expired frequency. ---------- Verify on an actual or simulated loss of offsite power signal: 1. De-energization of the safeguards buses; 2. Load shedding of the 480 V safeguards bus; 3. Standby emergency power source auto-starts from standby condition and energizes the safeguards buses, and 4. supplies bus loads for ≥ 5 minutes.	~~18 months~~ In accordance with the Surveillance Frequency Control Program
SR 3.8.2.5	----------NOTE---------- The following SR is not required to be performed if it is not met solely due to an expired frequency. ---------- Verify each standby emergency power source synchronizes with offsite power source upon a simulated restoration of offsite power and returns to ready-to-load operation.	~~18 months~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or more standby emergency power sources with inoperable starting air system(s).	D.1 Declare associated standby emergency power source(s) inoperable.	Immediately
E. Required Action and associated Completion Time not met. OR One or more standby emergency power sources' diesel fuel oil not within limits for reasons other than Condition A, B or C.	E.1 Declare associated standby emergency power source(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify each fuel oil storage tank contains ≥ 86.2% of fuel.	~~31 days~~
SR 3.8.3.2	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
SR 3.8.3.3	Verify each standby emergency power source air start bottle bank pressure is ≥ 165 psig.	~~31 days~~
SR 3.8.3.4	Check for and remove accumulated water from each fuel oil storage tank.	~~92 days~~

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources—Operating

LCO 3.8.4 The D-01, D-02, D-03, and D-04 DC electrical power subsystems shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One DC electrical power subsystem inoperable.	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," when any DC bus is de-energized. ----------	
	A.1 Restore DC electrical power subsystem to OPERABLE status.	2 hours
B. Required Action and Associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify correct battery terminal voltage is within limits on float charge.	~~7 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.2	Verify no visible corrosion at battery terminals and connectors. OR Verify battery connection resistance is within limits.	~~92 days~~ In accordance with the Surveillance Frequency Control Program
SR 3.8.4.3	Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration that could degrade battery performance.	~~12 months~~
SR 3.8.4.4	Remove visible terminal corrosion, and verify battery cell to cell and terminal connections are coated with anti-corrosion material.	~~12 months~~
SR 3.8.4.5	Verify battery connection resistance is within limits.	~~12 months~~
SR 3.8.4.6	Verify battery chargers D-07, D-08, and D-09, while operating at the current limit setting, each supply ≥ 320 amps at greater than or equal to the minimum established float voltage for ≥ 8 hours, and battery chargers D-107, D-108, and D-109, while operating at the current limit setting, each supply ≥ 420 amps at greater than or equal to the minimum established float voltage for ≥ 8 hours. OR Verify each battery charger can recharge the battery to the fully charged state within 24 hours while supplying the largest combined demands of the various continuous steady-state loads, after a battery discharge to the bounding design basis event discharge state.	~~18 months~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.7	----------NOTES---------- The modified performance discharge test in SR 3.8.4.8 may be performed in lieu of SR 3.8.4.7. ---------- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	~~18 months~~
SR 3.8.4.8	Verify battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	~~60 months~~ AND 12 months when battery shows degradation or has reached 85% of expected life with capacity < 100% of manufacturer's rating AND 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. OR One or more batteries with average electrolyte temperature of the representative cells < 60°F. OR One or more batteries with one or more battery cell parameters not within Table 3.8.6-1 Category C values.	B.1 Declare associated battery inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.6.1	Verify battery cell parameters meet Table 3.8.6-1 Category A limits.	~~7 days~~

(continued)

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.6.2	Verify battery cell parameters meet Table 3.8.6-1 Category B limits.	~~92 days~~ AND Once within 24 hours after a battery discharge < 105 V AND Once within 24 hours after a battery overcharge > 142.8 V
SR 3.8.6.3	Verify average electrolyte temperature of representative cells is ≥ 60°F.	~~92 days~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct inverter voltage, and alignment to required AC vital instrument buses.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 Inverters—Shutdown

LCO 3.8.8 Inverters shall be OPERABLE to support the onsite Class 1E AC vital instrument bus electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems—Shutdown."

APPLICABILITY: MODES 5 and 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required inverters inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	AND	
	A.2 Initiate action to restore required inverters to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct inverter voltage and alignments to required AC vital instrument buses.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more electrical power distribution subsystem inoperable.	A.1 Declare associated supported required feature(s) inoperable.	Immediately
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and power available for required AC, DC, and AC vital instrument bus electrical power distribution subsystems.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.10.1	Verify correct breaker alignments and power available for required AC, DC, and AC vital instrument bus electrical power distribution subsystems.	7 ~~days~~

In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.1 Boron Concentration

LCO 3.9.1 Boron concentrations of the Reactor Coolant System, the refueling canal, and the refueling cavity shall be maintained within the limit specified in the COLR.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Boron concentration not within limit.	A.1	Suspend positive reactivity additions.	Immediately
	AND		
	A.2	Initiate action to restore boron concentration to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Verify boron concentration is within the limit specified in the COLR.	~~72 hours~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Perform CHANNEL CHECK.	~~12 hours~~
SR 3.9.2.2	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	 ~~18 months~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Verify each required containment penetration is in the required status.	~~7 days~~
SR 3.9.3.2	----------NOTE---------- Not applicable to containment purge and exhaust valve(s) in penetrations closed to comply with LCO 3.9.3.c.1. ---------- Verify each required containment purge and exhaust valve actuates to the isolation position on an actual or simulated actuation signal.	~~18 months~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.4.1	Verify one RHR loop is in operation.	~~12 hours~~

In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	Verify one RHR loop is in operation.	~~12 hours~~
SR 3.9.5.2	Verify correct breaker alignment and indicated power available to the required RHR pump that is not in operation.	~~7 days~~

In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.6 *Refueling Cavity Water Level*

LCO 3.9.6 Refueling cavity water level shall be maintained ≥ 23 ft above the top of reactor vessel flange.

APPLICABILITY: During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refueling cavity water level not within limit.	A.1 Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify refueling cavity water level is ≥ 23 ft above the top of reactor vessel flange.	~~24 hours~~

In accordance with the Surveillance Frequency Control Program

5.5 Programs and Manuals

5.5.18 Control Room Envelope Habitability Program (continued)

g. An adequate supply of self contained breathing apparatus (SCBA) units in the CRE to protect CRE occupants from a hazardous chemical release.

h. Portable smoke ejection equipment per the Fire Protection Evaluation Report and Safe Shutdown Analysis Report to address a potential smoke challenge.

5.5.19 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.

Attachment 4

NextEra Energy Point Peach, LLC
Point Beach Nuclear Plant

License Amendment Request No. 273
Technical Specifications Bases
Marked-Up Pages

For Information Only

118 pages follow

Point Beach
Technical Specifications Basis
Marked-Up Pages

List of Affected Pages

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B 3.4.12-9	B 3.7.7-5
B 3.6.2-6	B 3.8.1-19

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2 with $k_{eff} \geq 1.0$, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth. In MODE 6, SDM is verified by observing that the requirements of LCO 3.9.1, "Boron Concentration" are met.

In MODE 2 with $k_{eff} < 1.0$ and MODES 3, 4, and 5, the SDM is verified, considering the listed reactivity effects:

a. RCS boron concentration;

b. Control and shutdown bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 24 hours~~ is based on the generally slow change in required boron concentration and the low probability of an accident occurring without the required SDM. This allows time for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the calculation.

BASES

ACTIONS (*continued*) B.1

If the core reactivity cannot be restored to within the 1% Δk/k limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. If the SDM for MODE 3 is not met, then the boration required by SR 3.1.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made, considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is performed prior to entering MODE 1 as an initial check on core conditions and design calculations at BOC. The SR is modified by a Note. The Note indicates that the normalization of predicted core reactivity to the measured value must take place within the first 60 effective full power days (EFPD) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. The required subsequent Frequency ~~of 31 EFPD,~~ following the initial 60 EFPD after entering MODE 1, is acceptable, based on the slow rate of core changes due to fuel depletion and the presence of other indicators (QPTR, AFD, etc.) for prompt indication of an anomaly.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 3.1.
2. FSAR, Chapter 14.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rod positions are within alignment limits ~~at a Frequency of 12 hours~~ provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The specified Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected.

SR 3.1.4.2

periodically

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2, tripping each control rod would result in radial or axial power tilts, or oscillations. Exercising each individual control rod ~~every 92 days~~ provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each control rod by 10 steps will not cause radial or axial power tilts, or oscillations, to occur. The ~~92 day~~ Frequency takes into consideration other information available to the operator in the control room and SR 3.1.4.1, which is performed more frequently and adds to the determination of OPERABILITY of the rods. Between required performances of SR 3.1.4.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable, but remains trippable, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

SR 3.1.4.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with all RCPs operating and the average moderator temperature ≥ 500°F to simulate a reactor trip under actual conditions.

This Surveillance is performed during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

BASES

ACTIONS (continued)

SDM will be verified by performing a reactivity balance calculation, considering the following listed reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. Power defect;

d. Fuel burnup;

e. Xenon concentration; and

f. Samarium concentration.

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1

If the shutdown banks cannot be restored to within their insertion limits within 2 hours, the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that the shutdown banks are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. This SR and Frequency ensure that the shutdown banks are withdrawn before the control banks are withdrawn during a unit startup. Typically, the individual rod position indicators are used to confirm shutdown bank insertion limits.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Since the shutdown banks are positioned manually by the control room operator, a verification of shutdown bank position ~~at a Frequency of 12 hours,~~ after the reactor is taken critical, is adequate to ensure that they are within their insertion limits. Also, the ~~12 hour~~ Frequency takes into account other information available in the control room for the purpose of monitoring the status of shutdown rods.

BASES

ACTIONS (continued)

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence, and overlaps limits provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

C.1

If Required Actions A.1 and A.2, or B.1 and B.2 cannot be completed within the associated Completion Times, the plant must be brought to MODE 2 with $K_{eff} < 1.0$, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits.

The estimated critical position (ECP) depends upon a number of factors, one of which is xenon concentration. If the ECP was calculated long before criticality, xenon concentration could change to make the ECP substantially in error. Conversely, determining the ECP immediately before criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Performing the ECP calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECP calculation with other startup activities.

SR 3.1.6.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Verification of the control bank insertion limits ~~at a Frequency of 12 hours~~ is sufficient to detect control banks that may be approaching the insertion limits since, normally, very little rod motion occurs in ~~12 hours.~~ the surveillance interval time period.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.6.3

The frequency

When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. ~~A Frequency of 12 hours~~ is consistent with the insertion limit check above in SR 3.1.6.2. Control banks which are fully withdrawn from the core as specified in the COLR, do not have to be verified. In the fully withdrawn position, sequence and overlap can no longer be verified.

REFERENCES

1. FSAR, Section 3.1.
2. 10 CFR 50.46.
3. FSAR, Chapter 14.

BASES

SURVEILLANCE REQUIREMENTS

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.8.1

Verification that the RCS lowest loop T_{avg} is ≥ 530°F will ensure that the unit is not operating in a condition that could invalidate the safety analyses. Verification of the RCS temperature ~~at a Frequency of 30 minutes~~ during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.2

Verification that THERMAL POWER is ≤ 5% RTP will ensure that the plant is not operating in a condition that could invalidate the safety analyses. Verification of THERMAL POWER ~~at a Frequency of 30 minutes~~ during the performance of PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.3

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration;

g. Isothermal temperature coefficient (ITC), when below the Point of Adding Heat (POAH);

h. Moderator Defect, when above the POAH; and

i. Doppler Defect, when above the POAH.

Using the ITC accounts for Doppler reactivity in this calculation when the reactor is subcritical, or critical but below the POAH, and the fuel temperature will be changing at the same rate as the RCS.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency ~~of 24 hours~~ is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM.

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.
2. 10 CFR 50.59.
3. Regulatory Guide 1.68, Revision 2, August, 1978.
4. ANSI/ANS-19.6.1-1985, December 13, 1985.
5. WCAP-9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology Report," July 1985.
6. WCAP-11618, including Addendum 1, April 1989.
7. WCAP-13360-P-A, "Westinghouse Dynamic Rod Worth Measurement Technique," January 1996.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.1

Verification that $F^C_Q(Z)$ is within its specified limits involves increasing $F^M_Q(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F^C_Q(Z)$. Specifically, $F^M_Q(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F^C_Q(Z) = F^M_Q(Z)$ 1.08 (Ref. 4). $F^C_Q(Z)$ is then compared to its specified limits.

The limit with which $F^C_Q(Z)$ is compared varies inversely with power above 50% RTP and directly with a function called K(Z) provided in the COLR.

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F^C_Q(Z)$ limit is met when RTP is achieved, because peaking factors generally decrease as power level is increased.

If THERMAL POWER has been increased by ≥ 10% RTP since the last determination of $F^C_Q(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium conditions at this higher power level (to ensure that $F^C_Q(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 31 EFPD~~ is adequate to monitor the change of power distribution with core burnup because such changes are slow and well controlled when the plant is operated in accordance with the Technical Specifications (TS).

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.2

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_Q(Z)$ limits. Because flux maps are taken in steady state conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the flux map data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values, calculated as a function of core elevation, Z, is called W(Z). Multiplying the measured total peaking factor, $F^C_Q(Z)$, by W(Z) gives the maximum $F_Q(Z)$ calculated to occur in normal operation, $F^W_Q(Z)$.

The limit with which $F^W_Q(Z)$ is compared varies inversely with power above 50% RTP and directly with the function K(Z) provided in the COLR.

The W(Z) curve is provided in the COLR for discrete core elevations. Flux map data are typically taken for 30 to 75 core elevations. $F^W_Q(Z)$ evaluations are not applicable for all axial core regions.

Depending on analyses, the top and bottom regions of the core may be excluded from the evaluation because of the low probability that these regions would be more limiting in the safety analyses and because of the difficulty of making a precise measurement in these regions (usually the top and bottom 10% or 15%).

This Surveillance has been modified by a Note that may require that more frequent surveillances be performed. If $F^W_Q(Z)$ is evaluated, an evaluation of the expression below is required to account for any increase to $F^M_Q(Z)$ that may occur and cause the $F_Q(Z)$ limit to be exceeded before the next required $F_Q(Z)$ evaluation.

BASES

SURVEILLANCE REQUIREMENTS (continued)

If the two most recent $F_Q(Z)$ evaluations show an increase in the expression

$$\text{maximum over } z \left[\frac{F_Q^C(Z)}{K(Z)} \right]$$

then $F^W_Q(Z)$ must be increased by the greater of a factor of 1.02, or by an appropriate factor specified in the COLR (Ref. 5), or $F_Q(Z)$ must be evaluated more frequently, each 7 EFPD. These alternative requirements prevent $F_Q(Z)$ from exceeding its limit for any significant period of time without detection.

Performing the Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q(Z)$ limit is met when RTP is achieved, because peaking factors are generally decreased as power level is increased. $F_Q(Z)$ is verified at power levels ≥ 10% RTP above the THERMAL POWER of its last verification, 12 hours after achieving equilibrium conditions to ensure that $F_Q(Z)$ is within its limit at higher power levels.

The Surveillance Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup. The Surveillance may be done more frequently if required by the results of $F_Q(Z)$ evaluations.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 31 EFPD~~ is adequate to monitor the change of power distribution because such a change is sufficiently slow, when the plant is operated in accordance with the TS, to preclude adverse peaking factors between ~~31 day~~ surveillances.

REFERENCES

1. 10 CFR 50.46, 1974.
2. FSAR, Section 14.2.6.
3. FSAR, Chapter 3.
4. WCAP - 7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties," June 1988.
5. WCAP-8403 (nonproprietary), Power Distribution Control and Load Following Procedures, Westinghouse Electric Corporation, September 1974.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The value of $F^N_{\Delta H}$ is determined by using the movable incore detector system to obtain a flux distribution map. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. The measured value of $F^N_{\Delta H}$ must be multiplied by 1.04 to account for measurement uncertainty before making comparisons to the $F^N_{\Delta H}$ limit.

After each refueling, $F^N_{\Delta H}$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The ~~31 EFPD~~ Frequency is acceptable because the power distribution changes relatively slowly over this amount of fuel burnup. Accordingly, this Frequency is short enough that the $F^N_{\Delta H}$ limit cannot be exceeded for any significant period of operation.

REFERENCES

1. FSAR, Section 14.2.6.
2. FSAR, Chapter 3.
3. 10 CFR 50.46.

ACTIONS (continued) D.1

If Required Action C.1 is not completed within its required Completion Time of 30 minutes, the axial xenon distribution starts to become significantly skewed with the THERMAL POWER ≥ 50% RTP. In this situation, the assumption that a cumulative penalty deviation time of 1 hour or less during the previous 24 hours while the AFD is outside its target band is acceptable at < 50% RTP, is no longer valid.

Reducing the power level to < 15% RTP within the Completion Time of 9 hours and complying with LCO penalty deviation time requirements for subsequent increases in THERMAL POWER ensure that acceptable xenon conditions are restored.

This Required Action must also be implemented either if the cumulative penalty deviation time is > 1 hour during the previous 24 hours, or the AFD is not within the target band and not within the acceptable operation limits.

SURVEILLANCE REQUIREMENTS SR 3.2.3.1

This Surveillance verifies that the AFD as indicated by the NIS excore channels is within the target band. The Surveillance Frequency ~~of 7 days~~ is adequate because the AFD is controlled by the operator and monitored by the process computer. Furthermore, any deviations of the AFD from the target band that is not alarmed should be readily noticed.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The AFD should be monitored and logged more frequently in periods of operation for which the power level or control bank positions are changing to allow corrective measures when the AFD is more likely to move outside the target band.

SR 3.2.3.2

periodically

This Surveillance requires that the target flux difference is updated ~~at a Frequency of 31 effective full power days (EFPD)~~ to account for small changes that may occur in the target flux differences in that period due to burnup by performing SR 3.2.3.3.

Alternatively, linear interpolation between the most recent measurement of the target flux differences and a predicted end of cycle value provides a reasonable update because the AFD changes due to burnup tend toward 0% AFD. When the predicted end of cycle AFD from the cycle nuclear design is different from 0%, it may be a better value for the interpolation.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.3.3

Measurement of the target flux difference is accomplished by taking a flux map when the core is at equilibrium xenon conditions, preferably at high power levels with the control banks nearly withdrawn. This flux map provides the equilibrium xenon axial power distribution from which the target value can be determined. The target flux difference varies slowly with core burnup.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

A Frequency of 31 EFPD after each refueling and ~~92 EFPD~~ periodically thereafter for remeasuring the target flux differences adjusts the target flux difference for each excore channel to the value measured at steady state conditions. This is the basis for the CAOC. Remeasurement at this Surveillance interval also establishes the AFD target flux difference values that account for changes in incore excore calibrations that may have occurred in the interim.

A Note modifies this SR to allow the predicted end of cycle AFD from the cycle nuclear design to be used to determine the initial target flux difference after each refueling.

REFERENCES

1. WCAP-8403 (nonproprietary), Power Distribution Control and Load Following Procedures, Westinghouse Electric Corporation, September 1974.

2. NS-TMA-2198, Westinghouse to NRC Letter, Operation and Safety Analysis Aspects of Improved Load Follow Package, January 31, 1980.

3. NS-CE-687, Westinghouse to NRC Letter, Power Distribution Control Analysis, July 16, 1975.

4. FSAR, Chapter 14.

BASES

ACTIONS (continued)

Required Action A.6 is modified by a Note that states that the peaking factor surveillances may only be done after the excore detectors have been normalized to restore QPTR to within limits (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are normalized to restore QPTR to within limits and the core returned to power.

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to < 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

SR 3.2.4.1 is modified by two Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is ≤ 75% RTP and the input from one Power Range Neutron Flux channel is inoperable. Note 2 allows performance of SR 3.2.4.2 in lieu of SR 3.2.4.1.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits. The Frequency ~~of 7 days~~ takes into account other information and alarms available to the operator in the control room.

For those causes of QPT that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt.

SR 3.2.4.2

This Surveillance is modified by a Note, which states that it is not required until 12 hours after the input from one or more Power Range Neutron Flux channels are inoperable and the THERMAL POWER is > 75% RTP.

BASES

SURVEILLANCE REQUIREMENTS (continued)

With an NIS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing SR 3.2.4.2 ~~at a Frequency of 12 hours~~ provides an accurate alternative means for ensuring that any tilt remains within its limits.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

For purposes of monitoring the QPTR when one power range channel is inoperable, the moveable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and any previous data indicating a tilt. The incore detector monitoring is performed with a full incore flux map.

With one NIS channel inoperable, the indicated tilt may be changed from the value indicated with all four channels OPERABLE. To confirm that no change in tilt has actually occurred, which might cause the QPTR limit to be exceeded, the incore result may be compared against previous flux maps. Nominally, quadrant tilt from the Surveillance should be within 2% of the tilt shown by the most recent flux map data.

REFERENCES

1. 10 CFR 50.46.
2. FSAR, Section 14.2.6.
3. FSAR, Chapter 3.

BASES

SURVEILLANCE REQUIREMENTS

The SRs for each RPS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RPS Functions.

Note that each channel of process protection supplies both trains of the RPS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.1.1

Performance of the CHANNEL CHECK ~~once every 12 hours~~ ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the NIS channel output ~~every 24 hours~~. If the calorimetric exceeds the NIS channel output by > 2% RTP, the NIS is not declared inoperable, but must be adjusted. If the NIS channel output cannot be properly adjusted, the channel is declared inoperable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Two Notes modify SR 3.3.1.2. The first Note indicates that the NIS channel output shall be adjusted consistent with the calorimetric results if the absolute difference between the NIS channel output and the calorimetric is > 2% RTP. The second Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 12 hour is allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels, calorimetric data are inaccurate. ~~The Frequency of every 24 hours is adequate. It~~ is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together these factors demonstrate the change in the absolute difference between NIS and heat balance calculated powers rarely exceeds 2% in ~~any 24 hour~~ period.

the surveillance

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The frequency

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output every 31 EFPD. SR 3.3.1.3 is performed by means of the moveable incore detection system. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

Two Notes modify SR 3.3.1.3. Note 1 indicates that the excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%.

Note 2 clarifies that the Surveillance is required only if reactor power is ≥ 50% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 50% RTP.

~~The Frequency of every 31 EFPD is adequate. It~~ is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT ~~every 31 days on a STAGGERED TEST BASIS.~~ This test shall verify OPERABILITY by actuation of the end devices.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. The independent test for bypass breakers is included in SR 3.3.1.13. The bypass breaker test shall include an undervoltage trip. A Note has been added to SR 3.3.1.4 to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Frequency ~~of every 31 days on a STAGGERED TEST BASIS is adequate. It~~ is based on industry operating experience, considering instrument reliability and operating history data.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST~~, every 31 days on a STAGGERED TEST BASIS.~~ The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All possible logic combinations, with and without applicable permissives, are tested for each protection function. The Frequency ~~of every 31 days on a STAGGERED TEST BASIS is adequate. It~~ is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.1.5 is modified by two Notes. Note 1 provides an 8 hour delay in the requirement to perform this Surveillance for the Source Range Neutron Flux trip function instrumentation when power is reduced to below P-6. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.5 is no longer required to be performed. If the unit is to be in MODE 2 below P-6 for > 8 hours, this Surveillance must be performed prior to 8 hours after reducing power below P-6.

Note 2 excludes the RCP Breaker Position (Two Loop), Reactor Coolant Flow-Low (Two Loop) and Underfrequency Bus A01 and A02 Trip Functions, and the P-6, P-7, P-8, P-9 and P-10 Interlocks. These functions/interlocks are tested ~~at an 18 month frequency~~ via SR 3.3.1.15.

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

BASES

SURVEILLANCE REQUIREMENTS (continued)

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 50% RTP and that 24 hours is allowed for performing the first surveillance after reaching 50% RTP.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The frequency

~~The Frequency of 92 EFPD is adequate. It~~ is based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.7 is the performance of a COT ~~every 92 days.~~

A COT is performed on each required channel to ensure the e channel will perform the intended Function.

Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

The difference between the current "as found" values and the NTSP must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The "as found" and "as left" values must also be recorded and verified to be within the required limits.

SR 3.3.1.7 is modified by a Note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3.

SR 3.3.1.7 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with the safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. The performance of these channels will be evaluated under the station's Corrective Action Program. Entry into the Corrective Action Program

BASES

SURVEILLANCE REQUIREMENTS (continued)

will ensure required review and documentation of the condition to establish a reasonable expectation for continued OPERABILITY. The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures, the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, except it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit condition. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within 92 days of the Frequencies prior to reactor startup and four hours after reducing power below P-10 and P-6. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels.

The Frequency of "4 hours after reducing power below P-10" (applicable to intermediate and power range low channels) and "4 hours after reducing power below P-6" (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency ~~of every 92 days thereafter~~ applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and four hours after reducing power below P-10 or P-6. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 4 hour limit. Four hours is a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 4 hours.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.8 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. The performance of these channels will be evaluated under the station's Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition to establish a reasonable expectation for continued OPERABILITY. The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures, the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable.

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT ~~and is performed every 31 days~~.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.10

~~A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling.~~ CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies ~~that the channel~~ responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology. The difference between the current "as found" values and the NTSP must be consistent with the drift allowance used in the setpoint methodology.

a

The Frequency ~~of 18 months~~ is based on the assumption of ~~an 18 month~~ calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time delays are adjusted to the prescribed values where applicable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.10 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. The performance of these channels will be evaluated under the station's Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition to establish a reasonable expectation for continued OPERABILITY. The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures, the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, ~~every 18 months.~~ This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric and flux map performed above 15% RTP. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors. The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed on the ~~18 month~~ Frequency.

surveillance

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.11 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. The performance of these channels will be evaluated under the station's Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition to establish a reasonable expectation for continued OPERABILITY. The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures, the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable.

SR 3.3.1.12

SR 3.3.1.12 is the performance of a COT of RPS interlocks ~~every 18 months.~~

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.1.13

SR 3.3.1.13 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, SI Input from ESFAS, and the Condenser Pressure-High and Circulating Water Pump Breaker Position inputs to the P-9 Interlock. ~~This TADOT is performed every 18 months.~~ The test shall independently verify the OPERABILITY of the undervoltage and shunt trip circuits for the Manual Reactor Trip Function for the Reactor Trip Breakers and the undervoltage trip circuits for the Reactor Trip Bypass Breakers.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, except that this test is performed prior to exceeding the P-9 interlock whenever the unit has been in MODE 3. This Surveillance is not required if it has been performed within the previous 31 days. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to exceeding the P-9 interlock.

SR 3.3.1.15

SR 3.3.1.15 is the performance of an ACTUATION LOGIC TEST on the RCP Breaker Position (Two Loop), Reactor Coolant Flow-Low (Two Loop) and Underfrequency Bus A01 and A02 Trip Functions, and P-6, P-7, P-8, P-9 and P-10 Interlocks ~~every 18 months~~.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The ~~18 month~~ frequency is based on the need to perform this surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the surveillance were performed with the reactor at power.

REFERENCES

1. FSAR, Chapter 7.
2. FSAR, Chapter 14.
3. IEEE-279-1968.
4. 10 CFR 50.49.
5. 10 CFR 50.67

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1

Performance of the CHANNEL CHECK ~~once every 12 hours~~ ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indicatin of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; this, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST on all ESFAS Automatic Actuation Logic ~~every 31 days on a STAGGERED TEST BASIS~~. This test includes the application of various simulated or actual input combinations in conjunction with each possible interlock state and verification of the required logic output. ~~The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It~~ is based on industry operating experience, considering instrument reliability and operating history data.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The frequency

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.3

SR 3.3.2.3 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found conservative with respect to the Allowable Values specified in Table 3.3.2-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 92 days~~ is justified in Reference 5.

SR 3.3.2.3 is modified by two Notes as identified in Table 3.3.2-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with the safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. The performance of these channels will be evaluated under the station's Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition to establish a reasonable expectation for continued OPERABILITY.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the nominal trip setpoint (NTSP). Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field trip setpoint), the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable. For Function 6.e, the NTSP is located in plant procedures.

The second Note also requires that the methodologies for calculating the as-left and as-found tolerances be in the FSAR Chapter 7, Reference 2.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay and verifying contact operation. ~~This test is performed every 18 months.~~

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. ~~This test is performed every 18 months.~~

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT ~~every 31 days~~. This test is a check of the Undervoltage Bus A01 and A02 Function.

The Frequency is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT. This test is a check of the Manual Actuation Functions. ~~It is performed every 18 months~~. The Frequency is adequate, based on industry operating experience, and is consistent with the typical refueling cycle.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a CHANNEL CALIBRATION.

~~A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling~~. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the setpoint methodology. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

a

The Frequency ~~of 18 months~~ is based on the assumption of ~~an 18 month~~ calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

BASES

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 applies to each PAM instrumentation Function in Table 3.3.3-1. SR 3.3.3.2 applies to each PAM instrumentation Function in Table 3.3.3-1, except Function 12. SR 3.3.3.3 applies to Function 12 only.

SR 3.3.3.1

Performance of the CHANNEL CHECK ~~once every 31 days~~ ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 31 days~~ is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2

~~A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling~~. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. This SR is modified by a Note that specifies the CHANNEL CALIBRATION of the Containment Area Radiation (High Range) detectors shall consist of a verification of a response to a source. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the Core Exit thermocouple sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.3.3

SR 3.3.3.3 is the performance of a TADOT of Containment Isolation Valve Position Indication. ~~This TADOT is performed every 18 months.~~ The test shall independently verify the OPERABILITY of containment isolation valve position indication against the actual position of the valves.

The Frequency is based on the known reliability of the Functions and has been shown to be acceptable through operating experience.

REFERENCES

1. NRC SER Letter, "Conformance to Regulatory Guide 1.97 for the Point Beach Nuclear Plant Units 1 and 2," July 11, 1986.

2. Regulatory Guide 1.97, Revision 2, December 1980.

3. NUREG-0737, Supplement 1, "TMI Action Items."

4. NRC SER Letter, "Point Beach Nuclear Power Plant, Units 1 and 2 – Emergency Response Capability – Conformance to Regulatory Guide 1.97, Revision 2", February 22, 2002.

BASES

ACTIONS (continued) E.1 and E.2

If the Required Action and associated Completion Time of Condition A for the 480 V loss of voltage Function or Condition D are not met, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 in 6 hours and in MODE 5 in 36 hours. The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS SR 3.3.4.1

Performance of the CHANNEL CHECK ~~once every 12 hours~~ ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.4.2

SR 3.3.4.2 is the performance of a TADOT. ~~This test is performed every 31 days~~. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. The Frequency is based on the known reliability of the relays and controls and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.3

SR 3.3.4.3 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay, as shown in Reference 1.

~~A CHANNEL CALIBRATION is performed every 18 months.~~ CHANNEL CALIBRATION is a complete check of the instrument loop, excluding the potential transformer sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The degraded voltage function time delay Allowable Values apply to specific relays. The first time delay Allowable Value applies to the bus degraded voltage relay (SI signal present). The second time delay Allowable Value applies to the bus time delay relay. The sum of these two time delay Allowable Values constitutes the required time delay when no SI signal is present.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 18 months~~ is based on operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of ~~an 18 month~~ the calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. FSAR Section 8.8
2. FSAR Chapter 14

BASES

ACTIONS (continued)

If a Function is inoperable, 7 days is permitted to restore the Function to OPERABLE status from the time the Condition was entered for that Function. The 7 day Completion Time is the same as for inoperable CREFS. The basis for this Completion Time is the same as provided in LCO 3.7.9. If the Function cannot be restored to OPERABLE status, CREFS must be placed in the emergency mode of operation (Mode 5). Placing CREFS in the emergency mode of operation accomplishes the actuation instrumentation's safety function.

B.1, B.2 and B.3

Condition B applies when the Required Action and associated Completion Time for Condition A have not been met. If movement of recently irradiated fuel assemblies is in progress, this activity must be suspended immediately to reduce the risk of accidents that would require CREFS actuation. In addition, if any unit is in MODE 1, 2, 3, or 4, the unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions for Condition B are modified by a Note that states that Required Action B.1 is not applicable for inoperability of the Containment Isolation actuation function. This note is necessary because the Applicability for the Containment Isolation actuation function is Modes 1, 2, 3, and 4. The Containment Isolation actuation function is not used for mitigation of accidents involving the movement of recently irradiated fuel assemblies.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.5-1 determines which SRs apply to which CREFS Actuation Functions.

SR 3.3.5.1

Performance of the CHANNEL CHECK ~~once every 12 hours~~ ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. However, in the case of the control room area and control room intake noble gas monitors, no independent instrument channel exist, therefore, the CHANNEL CHECK for these monitors will consist of a qualitative assessment of expected channel behavior, based on current plant and

BASES

SURVEILLANCE REQUIREMENTS (continued)

control room conditions. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The Frequency is based on operating experience that demonstrates channel failure is rare.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.5.2

A COT is performed ~~once every 92 days~~ on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the CREFS actuation. The setpoints shall be left consistent with the unit specific calibration procedure tolerance. The Frequency is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience.

SR 3.3.5.3

~~A CHANNEL CALIBRATION is performed every 18 months or approximately at every refueling~~. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES

FSAR. Section 14.3.5.

B 3.3 INSTRUMENTATION

B 3.3.6 Boron Dilution Alarm

BASES

BACKGROUND	The primary purpose of the Boron Dilution Alarm (i.e., "BA FLOW DEVIATION OR POTENTIAL DILUTION IN PROGRESS") is to alert the operator to the potential for an inadvertent addition of unborated primary grade water into the Reactor Coolant System (RCS) when the reactor is in the cold shutdown condition (i.e., MODE 5).
APPLICABLE SAFETY ANALYSES	The Boron Dilution Alarm is actuated when the Reactor Makeup Water To Boric Acid Blender Flow Control Valve (FCV-111) is not shut. The accident analyses require operator action within 15 minutes of the initiation of reactor coolant dilution to prevent a loss of shutdown margin. The Boron Dilution Alarm is necessary to ensure operator awareness of the potential for an inadvertent boron dilution event.
LCO	LCO 3.3.6 provides the requirements for OPERABILITY of the Boron Dilution Alarm.
APPLICABILITY	The Boron Dilution Alarm must be OPERABLE in MODE 5, because the safety analysis identifies the alarm as the primary means of alerting the operator to the potential for an inadvertent boron dilution of the RCS with the unit in this condition.
ACTIONS	A.1 With the Boron Dilution Alarm inoperable, Required Action A.1 requires the closure of isolation valve(s) to prevent the flow of unborated water through FCV-111, Reactor Makeup Water To Boric Acid Blender Flow Control Valve, into the RCS. This Required Action can be satisfied by closure of FCV-111. The Completion Time of 1 hour is adequate to secure the valve(s).
SURVEILLANCE REQUIREMENTS	SR 3.3.6.1 SR 3.3.6.1 requires the performance of a TADOT ~~every 18 months~~, to ensure the Boron Dilution Alarm is operational. The Frequency ~~of 18 months~~ is consistent with the typical industry refueling cycle. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. FSAR, Chapter 14.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the ~~12 hour~~ Surveillance Frequency for pressurizer pressure is sufficient to ensure the pressure can be restored to a normal operation, steady state condition following load changes and other expected transient operations. The ~~12 hour~~ interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.1.2

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the ~~12 hour~~ Surveillance Frequency for RCS average temperature is sufficient to ensure the temperature can be restored to a normal operation, steady state condition following load changes and other expected transient operations. The ~~12 hour~~ interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.3

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance ~~once every 18 months~~ allows the installed RCS flow instrumentation to be calibrated and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

The Frequency ~~of 18 months~~ reflects the importance of verifying flow after a refueling outage when the core has been altered, which may have caused an alteration of flow resistance.

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until 24 hours after ≥ 90% RTP. This exception is appropriate since the heat balance requires the plant to be at a minimum of 90% RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 24 hours after reaching 90% RTP.

REFERENCES

1. FSAR. Section 14.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 540°F ~~every 12 hours~~. The SR to verify RCS loop average temperatures ~~every 12 hours~~ takes into account indications and alarms that are continuously available to the operator in the control room and is consistent with other routine Surveillances which are typically performed once per shift. In addition, operators are trained to be sensitive to RCS temperature during approach to criticality and will ensure that the minimum temperature for criticality is met as criticality is approached.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

FSAR. Section 14, Table 14.0-1.

BASES

ACTIONS (continued

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required ~~every 30 minutes~~ when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, ~~30 minutes~~ the frequency permits assessment and correction for minor deviations within a reasonable ~~time~~.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

BASES

APPLICABILITY (continued)

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, "RCS Loops — MODE 3";
LCO 3.4.6, "RCS Loops — MODE 4";
LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops — MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level" (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification ~~every 12 hours~~ that each RCS loop is in operation. Verification includes flow rate, temperature, or pump status ~~monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB.~~ The Frequency ~~of 12 hours~~ is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 14.

BASES

ACTIONS (continued) B.1

If restoration is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

C.1, C.2, and C.3

If two RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, place the Rod Control System in a condition incapable of rod motion (e.g., CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets). All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification ~~every 12 hours~~ that one RCS loop is in operation. Verification includes flow rate, temperature, and pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency ~~of 12 hours~~ is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY.
SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 35% for required RCS loops. If the SG secondary side narrow range water level is < 35%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The minimum steam generator narrow range level limit (35%) includes instrument uncertainty. The ~~12 hour~~ Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs. →

REFERENCES None.

BASES

ACTIONS (continued) C.1 and C.2

If no loop is OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RCS or RHR loop to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification ~~every 12 hours~~ that one RCS or RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency ~~of 12 hours~~ is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY.
SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 35%. If the SG secondary side narrow range water level is < 35%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The minimum steam generator narrow range level limit (35%) includes instrument uncertainty. The ~~12 hour~~ Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency ~~of 7 days~~ is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES None.

BASES

APPLICABILITY (continued)

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SG has secondary side water level < 35% narrow range, redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water level. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification ~~every 12 hours~~ that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency ~~of 12 hours~~ is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.2

Verifying that at least one SG is OPERABLE by ensuring its secondary side narrow range water level is ≥ 35% narrow range ensures an alternate decay heat removal method via natural circulation (Ref. 1) in the event that the second RHR loop is not OPERABLE. The minimum steam generator narrow range level limit (35%) includes instrument uncertainty. If both RHR loops are OPERABLE, this Surveillance is not needed. The ~~12 hour~~ Frequency is considered adequate in view of ~~other~~ indications available in the control room to alert the operator to the loss of SG level.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to ~~the RHR pump. If secondary side water level is ≥ 35% narrow range in at least one SG, this Surveillance is not needed.~~ The Frequency ~~of 7 days~~ is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification ~~every 12 hours~~ that one loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency ~~of 12 hours~~ is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.8.2

Verification that the required number of pumps are OPERABLE ensures that additional pumps can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Frequency ~~of 7 days~~ is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES None.

BASES

ACTIONS (continued) C.1 and C.2

If the pressurizer cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1 or B.1, or the pressurizer water level is not within the limit of MODE 2 and MODE 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Surveillance Requirement is met when indicated pressurizer level, which includes instrument uncertainty, is ≤ 52% in MODE 1 and ≤ 88% in MODE 2 and MODE 3. ~~The Frequency of 12 hours corresponds to verifying the parameter each shift. The 12 hour~~ interval has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is within safety analyses assumptions. Alarms are also available for early detection of abnormal level indications.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The

SR 3.4.9.2

The required pressurizer heaters are heaters that are powered from a safeguards bus. The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to have a combined capacity of ≥ 100kW. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Frequency ~~of 92 days~~ is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 14.
2. NUREG-0737, November 1980.

BASES

ACTIONS (continued) removed once it is closed) are adequate to address the condition. While it may be desirable to also place the PORV(s) in manual control, this may not be possible for all causes of Condition B or E entry with PORV(s) inoperable and not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunction(s)).

G.1 and G.2

If the Required Actions of Condition F are not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours with T_{avg} reduced to < 500°F within 12 hours. The allowed Completion 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 MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed if needed. The basis for the Frequency ~~of 92 days~~ is the ASME Code (~~Ref.~~ 3). If the block valve is closed to isolate a PORV that is capable of being manually cycled, the OPERABILITY of the block valve is of importance, because opening the block valve is necessary to permit the PORV to be used for manual control of reactor pressure. If the block valve is closed to isolate an inoperable PORV that is incapable of being manually cycled, the maximum Completion Time to restore the PORV and open the block valve is 72 hours, which is well within the allowable limits (25%) to extend the block valve Frequency ~~of 92 days~~. Furthermore, these test requirements would be completed by the reopening of a recently closed block valve upon restoration of the PORV to OPERABLE status.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Note modifies this SR by stating that it is not required to be met with the block valve closed, in accordance with the Required Action of this LCO.

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated for mitigation of an SGTR. The Frequency ~~of 18 months~~ is based on a typical refueling cycle and industry accepted practice.

No changes - For Information only

BASES

ACTIONS (continued)

c. The LTOP System is inoperable for any reason other than Condition A, B, C, D or E.

The vent path must have a venting capability equivalent to or greater than a PORV to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 and SR 3.4.12.2

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, a maximum of one SI pump is verified capable of injecting into the RCS and the accumulators are verified to be isolated from the RCS when accumulator pressure is ≥ the maximum RCS pressure for existing cold leg temperature allowed by the P/T limit curves provided in the PTLR.

The SI pump is rendered incapable of injecting into the RCS through removing the power from the pump by racking the breaker out under administrative control. An alternate method of LTOP control may be employed using at least two independent means to prevent a pump start such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in pull out and at least one valve in the discharge flow path being closed.

The accumulators are isolated from the RCS by closing the discharge isolation valves and removing power from the valve operators under administrative controls. SR 3.4.12.2 is modified by a Note specifying that this verification is only required when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR. If accumulator pressure is less than this limit, no verification is required since the accumulator cannot pressurize the RCS beyond the LTOP limits.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency ~~of 12 hours~~ is sufficient, considering the administrative controls and indications and alarms available to the operator in the control room, to verify the required status of the equipment.

SR 3.4.12.3

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The RCS vent path with a venting capability equivalent or greater than a PORV is proven OPERABLE by verifying its open condition either:

a. ~~Once every 12 hours for~~ a valve that is not locked (valves that are sealed or secured in the open position are considered "locked" in this context).

For

b. ~~Once every 31 days for~~ other vent path(s) (e.g., a vent or a valve that is locked, sealed, or secured in position). A removed pressurizer safety valve or open manway also fits this category.

The passive vent path arrangement must only be open when required to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12.c.2.

SR 3.4.12.4

The required trains of LTOP must be verified enabled ~~every 72 hours~~ to provide the flow path for each required PORV to perform its function when actuated. A LTOP train is verified enabled by ensuring its enabling switch is in the correct position and that the associated PORV Block Valve is open.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required removed, and the manual operator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The ~~72 hour~~ Frequency is considered adequate in view of other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

SR 3.4.12.5

Performance of a COT is required ~~every 31 days~~ on each required PORV to verify and, as necessary, adjust its lift setpoint. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The COT will verify the setpoint is within the PTLR allowed maximum limits in the PTLR. PORV actuation could depressurize the RCS and is not required.

SR 3.4.12.6

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required ~~every 18 months~~ to adjust the whole channel so that it responds and the valve opens within the required range and accuracy to known input.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.7 and SR 3.4.12.8

Operating the PORVs, the solenoid air control valves and the check valves on the nitrogen gas bottles ensures the PORVs and PORV control system will actuate properly when called upon. The Frequency ~~of 18 months~~ is based on a typical refueling cycle and the frequency of other surveillances used to demonstrate PORV OPERABILITY.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11.
3. ASME, Boiler and Pressure Vessel Code, Section III.
4. Technical Requirements Manual 2.2, Pressure Temperature Limits Report.
5. 10 CFR 50, Section 50.46.
6. 10 CFR 50, Appendix K.
7. Generic Letter 90-06.
8. Engineering Evaluation 2001-0037, Rev 0, 12/13/01, Evaluation of Unbolted Head as an RCS vent path.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB 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 an RCS water inventory balance.

The RCS water inventory balance must be met with the reactor at steady state operating conditions (i.e., stable temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The Surveillance is modified by two Notes. Note 1 states that this SR is not required to be performed until 12 hours after establishing 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 operation 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 RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

Note 2 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The ~~72 hour~~ Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.13.2

This SR verifies that primary to secondary LEAKAGE is less or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.17, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 4. 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 Surveillance is modified by a 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 RCP 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. 4).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR Section 1.3.3.
2. FSAR, Section 14.
3. NEI 97-06, "Steam Generator Program Guidelines."
4. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."
5. 10 CFR 50.67, Accident Source Term.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Frequency ~~of 12 hours~~ is based on instrument reliability and is reasonable for detecting off normal conditions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.15.2 and SR 3.4.15.3

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency ~~of 18 months~~ is a typical refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable.

REFERENCES

1. FSAR Section 1.3.3.
2. FSAR, Section 6.5.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the noble gas specific activity of the reactor coolant ~~at least once every 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating ~~conditions~~. The ~~7 day~~ Frequency considers the low probability of a gross fuel failure during the time.

Due to the inherent difficulty in detecting Kr-85 in a reactor coolant sample due to masking from radioisotopes with similar decay energies, such as F-18 and I-134, it is acceptable to include the minimum detectable activity for Kr-85 in the SR 3.4.16.1 calculation. If a specific noble gas nuclide listed in the definition of DOSE EQUIVALENT Xe-133 is not detected, it should be assumed to be present at the minimum detectable activity.

A Note modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be preformed in those MODES, prior to entering MODE 1.

SR 3.4.16.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This surveillance is performed to ensure iodine specific activity remains within the LCO limit during normal operation and following fast power changes when iodine spiking is more apt to occur. The ~~14 day~~ Frequency is adequate to trend changes in the iodine activity level, considering noble gas activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following iodine spike initiation; samples at other times would provide inaccurate results.

The Note modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be preformed in those MODES, prior to entering MODE 1.

BASES

ACTIONS (continued)

D.1

If both accumulators are inoperable, the water volume and boron concentrations assumed in the various accident analyses may not be delivered to the RCS therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve should be verified to be fully open ~~every 12 hours~~. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed valve could result in not meeting accident analyses assumptions. ~~This~~ Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The

SR 3.5.1.2 and SR 3.5.1.3

~~Every 12 hours,~~ borated water volume and nitrogen cover pressure are verified for each accumulator. ~~This~~ Frequency is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, ~~a 12 hour~~ Frequency usually allows the operator to ~~identify~~ changes before limits are reached. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

the

The limits for minimum and maximum accumulator water volume (1100 ft^3 and 1136 ft^3, respectively) and accumulator pressure (700 psig and 800 psig, respectively) include instrument uncertainty. The Surveillance Requirement is met when indicated accumulator water level is $\geq$ 6% and $\leq$ 49% and indicated accumulator pressure is $\geq$ 700 psig and $\leq$ 800psig. *

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator ~~every 31 days~~ since the static design of the accumulators limits the ways in which the concentration can be changed. The ~~31 day~~ Frequency is adequate to identify changes that ~~could~~ occur from mechanisms such as stratification or inleakage. Sampling the affected accumulator within 24 hours after a 5% volume increase will identify whether inleakage has caused a reduction in boron concentration to below the required limit. It is not necessary to verify boron concentration if the added water inventory is from the refueling water storage tank (RWST), and the water contained in the RWST is within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 5).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.5

Verification ~~every 31 days~~ that power is removed from each accumulator isolation valve operator when the RCS pressure is > 1000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, no accumulators would be available for injection in the event ~~of a LOCA.~~ Since power is removed under administrative control, the ~~31 day~~ Frequency will provide adequate assurance that power is removed.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR allows power to be supplied to the motor operated isolation valves when RCS pressure is ≤ 1000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns.

REFERENCES

1. FSAR, Section 6.2.
2. 10 CFR 50.46.
3. FSAR, Chapter 14.
4. WCAP-15049-A, Rev. 1, April 1999.
5. NUREG-1366, February 1990.

BASES

ACTIONS (continued)

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 5) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

With more than one component inoperable such that both ECCS trains are not available, the facility is in a condition outside design and licensing basis. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. The allowed Completion 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.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a non-accident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The ~~31 day~~ Frequency is appropriate because the valves are operated under administrative control, and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.2

The ECCS pumps are normally in a standby, nonoperating mode. As such, flow path piping has the potential to develop voids and pockets of entrained gases. Maintaining the ECCS pumps and accessible portions of ECCS suction piping, including cross-connect piping to RHR, free of gas quantities that could jeopardize ECCS operability, ensures that the system will perform properly, injecting its full capacity into the RCS

BASES

SURVEILLANCE REQUIREMENTS (continued)

upon demand. This is accomplished by venting the SI pumps and accessible portions of ECCS suction piping. Performance of this SR also includes venting accessible portions of the piping from the ECCS pumps to the RCS. This will also prevent pump cavitation and minimize pumping noncondensible gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling. The ~~31 day~~ Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping and the procedural controls governing system operation.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.3

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program, which implements the requirements of the ASME OM Code, providing the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.4 and SR 3.5.2.5

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The ~~18 month~~ Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned plant transients if the Surveillances were performed with the reactor at power. The ~~18 month~~ Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.6

Periodic inspections of the containment sump suction inlet ensure that it is unrestricted and stays in proper operating condition. The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and on the need to have access to the location. This Frequency has been found to be sufficient to detect abnormal degradation and is confirmed by operating experience.

REFERENCES

1. FSAR, Section 6.1.1.
2. 10 CFR 50.46.
3. FSAR, Section 6.2.1.
4. FSAR, Chapter 14, "Accident Analysis."
5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified ~~every 24 hours~~ to be within the limits assumed in the accident analyses band. This Frequency is sufficient to identify a temperature change that would approach either limit and has been shown to be acceptable through operating experience. The minimum and maximum RWST water temperature limits (42.5°F and 97.5°F, respectively) include instrument uncertainty.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.4.2

The RWST water volume should be verified ~~every 7 days~~ to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and to support continued ECCS and Containment Spray System pump operation on recirculation. Since the RWST volume is normally stable and is protected by an alarm, ~~a 7 day~~ the Frequency is appropriate and has been shown to be acceptable through operating experience. The minimum RWST water volume limit (275,000 gallons) includes instrument uncertainty. The Surveillance Requirement is met when indicated RWST level is ≥ 95%.

SR 3.5.4.3

The boron concentration of the RWST should be verified ~~every 7 days~~ to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. Since the RWST volume is normally stable, ~~a 7 day~~ the sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

REFERENCES

1. FSAR. Chapter 5 and Chapter 14.

No changes - For Information only

BASES

ACTIONS (continued) considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door and its associated equalization valve are maintained closed in each affected air lock.

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria specified in the Containment Leakage Rate Testing Program for the air locks, limits airlock leakage to a small percentage of the combined Type B and C leakage limit.

The Frequency is required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock bulkhead does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock bulkhead is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria which is applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

SR 3.6.2.2

The bulkhead doors and equalization valves are interlocked with each other to prevent simultaneous opening of the doors and or equalizing valves in the redundant bulkheads. Since both the inner and outer bulkheads of an air lock are designed to withstand the maximum expected post accident containment pressure, OPERABILITY of either

BASES

SURVEILLANCE REQUIREMENTS (continued)

bulkhead will support containment OPERABILITY. Thus, the airlock interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors and or equalizing valves in redundant bulkheads will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the containment air lock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed ~~every 24 months~~ at the frequency specified in the Surveillance Frequency Control Program. The ~~24 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of containment OPERABILITY if the Surveillance were performed with the reactor at power. The ~~24 month~~ Frequency for the interlock is justified based on generic operating experience. The Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during the use of the airlock.

REFERENCES

1. Technical Specification 1.1
2. FSAR, Section 5.5.

ACTIONS (continued)

allows these devices to be verified closed by administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

D.1 and D.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Deleted

SR 3.6.3.2

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. Since verification of valve position for containment isolation valves outside containment is relatively easy, the ~~31 day~~ Frequency is based on engineering

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

judgment and was chosen to provide added assurance of the correct positions. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

This Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.4

Verifying that the isolation time of each automatic power operated containment isolation valve is within Inservice Testing Program limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the Inservice Testing Program.

SR 3.6.3.5

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under ~~administrative controls.~~ The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 14.
2. FSAR, Section 5.2.
3. Generic Issue B-24.
4. NRC SE dated 02/19/2008 for LAR 249

BASES

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 1 hour. The Required Action is necessary to return operation to within the limits established to ensure that containment design pressures are not exceeded. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that unit operation remains within the limits established to ensure that containment design pressures are not exceeded. The minimum and maximum containment pressure limits include instrument uncertainty. The Surveillance Requirement is met when indicated containment pressure is ≥ - 1.0 psig and ≤ + 1.0 psig. The ~~12 hour~~ Frequency of this SR was developed based on operating experience related to trending of containment pressure variations during the applicable MODES. Furthermore, the ~~12 hour~~ Frequency is considered adequate in view of other indications available in the control room.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 14.
2. FSAR, Section 5.5.2.
3. 10 CFR 50, Appendix K

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limit of the LCO, it must be restored to within limit within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

B.1 and B.2

If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying that containment average air temperature is within the LCO limits ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, an arithmetic average is calculated using measurements taken at locations within the containment selected to provide a representative sample of the overall containment atmosphere. The containment average air temperature limits include instrument uncertainty. The Surveillance Requirement is met when indicated containment temperature is ≤ 112.5°F (for a single channel), ≤ 115.7°F (two channels averaged), or ≤ 116.3°F (three channels ~~averaged)~~. The ~~24 hour~~ Frequency of this SR is considered acceptable based on observed slow rates of temperature increase within containment as a result of environmental heat sources (due to the large volume of containment).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

ACTIONS (continued)

The 144 hour portion of the Completion Time for Required Action C.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Section 1.3 for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

D.1

With one containment cooler service water outlet valve inoperable, the containment cooling water outlet valve must be restored to OPERABLE status within 72 hours. During this period, the remaining containment cooler service water outlet valve is capable of providing 100% of assumed cooling water flow to all four containment accident fan coolers. The 72 hour Completion Time was developed taking into account the auto open and flow capability afforded by the redundant cooling water outlet valve, and the low probability of DBA occurring during this period.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C or D of this LCO are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray flow path provides assurance that the proper flow paths will exist for Containment Spray System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification that those valves outside containment (only check valves are inside containment) and capable of potentially being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.2

Operating each containment cooling unit's accident fan ensures that all accident fans are OPERABLE and that all associated indications are functioning properly. It also ensures that blockage, fan or motor failure, can be detected for corrective action. Acceptable performance is verified through verification of main control panel accident fan run indication, motor running amps, and clearing of low flow alarms. The ~~31 day~~ Frequency was developed considering the known reliability of the accident fans and indications, the redundancy available, and the low probability of significant degradation of the accident fans occurring between surveillances. It has also been shown to be acceptable through operating experience.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.3

Verifying that each containment accident fan cooler unit can achieve its assumed post accident flow rate with at least one containment accident fan cooler service water outlet valve open provides assurance that the design flow rate assumed in the safety analyses will be achieved (Ref. ~~3).~~ The Frequency was developed considering the known reliability of the Cooling Water System, the redundancy available, and the low probability of a significant degradation of flow occurring between surveillances.

SR 3.6.6.4

Verifying each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by the ASME Code (Ref. 4). Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on a test line. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by abnormal performance. The Frequency of the SR is in accordance with the Inservice Testing Program.

SR 3.6.6.5 and SR 3.6.6.6

These SRs require verification that each automatic containment spray and containment accident fan cooler service water outlet valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated actuation of a containment Hi-Hi

SURVEILLANCE REQUIREMENTS (continued)

pressure signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The ~~18 month~~ Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillances were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillances when performed at the ~~18 month~~ Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.7

This SR requires verification that each containment accident fan cooler unit accident fan actuates upon receipt of an actual or simulated safety injection signal. The ~~18 month~~ Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. See SR 3.6.6.5 and SR 3.6.6.6, above, for further discussion of the basis for the ~~18 month~~ Frequency.

SR 3.6.6.8

This SR verifies proper operation of the containment accident fan cooler unit backdraft dampers. The backdraft damper of concern is the one installed in the discharge flowpath of the normal fan. This damper prevents back flow which would bypass the cooler coils when the accident fan is in operation and the normal fan is not in operation. The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and engineering judgment.

SR 3.6.6.9

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. Due to the passive design of the nozzle, ~~a test at 10 year intervals~~ is considered adequate to detect obstruction of the nozzles.

the frequency

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

ACTIONS (continued)

7.0 and 10.0 The 72 hour Completion Time takes into account the redundant NaOH delivery capability and the low probability of a DBA occurring during this period.

B.1

If the Spray Additive System is inoperable for any reason other than Condition A, at least one flowpath must be restored to OPERABLE status within 1 hour. The Completion Time of 1 hour reflects the loss of the capability to add NaOH to the containment sump during an accident and the importance of restoring the system to an OPERABLE status.

C.1 and C.2

If the Required Action and Completion Time of Condition A or B are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows 48 hours for restoration of the Spray Additive System in MODE 3 and 36 hours to reach MODE 5. This is reasonable when considering the reduced pressure and temperature conditions in MODE 3 for the release of radioactive material from the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Verifying the correct alignment of Spray Additive System manual, power operated, and automatic valves in the spray additive flow path provides assurance that the system is able to provide additive to the Containment Spray System in the event of a DBA. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification that those valves outside containment and capable of potentially being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.2

To provide effective iodine removal, the containment spray must be an alkaline solution. Since the RWST contents are normally acidic, the volume of the spray additive tank must provide a sufficient volume of

BASES

SURVEILLANCE REQUIREMENTS (continued)

spray additive to adjust pH for all water injected. This SR is performed to verify the availability of sufficient NaOH solution in the Spray Additive System. The limit for minimum spray additive volume includes instrument uncertainty. The Surveillance Requirement is met when indicated SAT level is ≥ 43%. The ~~184 day~~ Frequency was developed based on the low probability of an undetected change in tank volume occurring during the SR interval (the tank is isolated during normal unit operations). Tank level is also indicated and alarmed in the control room, so that there is high confidence that a substantial change in level would be detected.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.3

This SR provides verification of the NaOH concentration in the spray additive tank and is sufficient to ensure that the spray solution being injected into containment is at the correct pH level. The ~~184 day~~ Frequency is sufficient to ensure that the concentration level of NaOH in the spray additive tank remains within the established limits. This is based on the low likelihood of an uncontrolled change in concentration (the tank is normally isolated) and the probability that any substantial variance in tank volume will be detected.

SR 3.6.7.4

This SR provides verification that each automatic valve in the Spray Additive System flow path actuates to its correct position. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage 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 the Surveillance when performed at the ~~18 month~~ Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Chapter 14.3.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This test is conducted in MODE 2 under low steam flow conditions (≤ 5% steam flow) at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODES 2 and 3 prior to performing the SR. This allows a delay of testing to establish conditions consistent with those under which the acceptance criterion was generated.

SR 3.7.2.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR verifies that each MSIV will actuate to its isolation position on a actuation isolation 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 normally pass this Surveillance when performed at the ~~18 month~~ Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that allows entry into and operation in MODES 2 and 3 prior to performing the SR. This allows delaying testing until conditions where the testing can be performed are established.

SR 3.7.2.3

This SR verifies that each main steam non-return check valve can close. As the non-return check valves are not tested at power, they are exempt from the ASME Code (Ref. 4) requirements during operation in MODE 1, 2, or 3. The Frequency is in accordance with the Inservice Testing Program. Operating experience has shown that these components usually pass the Surveillance when performed at the Frequency required by the Inservice Testing Program. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 10.1.
2. FSAR, Section 14.2.5.
3. 10 CFR 100.11.
4. ASME Boiler and Pressure Vessel Code, Section XI, OM Code, Code for Operation and Maintenance of Nuclear Power Plants.
5. TRM 4.7, Inservice Testing Program.

BASES

ACTIONS (continued) E.1 and E.2

If the MFW isolation systems cannot be restored to OPERABLE status, isolated, or secured within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR verifies that each MFIV, MFRV and MFRV bypass valve will actuate to its isolation position on a actuation isolation signal (i.e., Safety Injection) 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 3.7.3.2

This SR verifies the closure time of each MFIV, MFRV, and MFRV bypass valve is within limits and within that assumed in the accident and containment analyses. This SR also verifies the valve closure time in accordance with the Inservice Testing Program. 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 (Ref 2.), quarterly stroke requirements during operation in MODES 1 and 2.

The Frequency for this SR is in accordance with the Inservice Testing Program.

BASES

ACTIONS (continued) the low probability of an event occurring during this period that would require the ADV flowpath.

B.1

With two ADV flowpaths inoperable, action must be taken to restore one ADV flowpath to OPERABLE status. Since the block valve can be closed to isolate an ADV, some repairs may be possible with the unit at power. The 1 hour Completion Time is reasonable to repair an inoperable ADV flowpath, based on the availability of the Steam Bypass System and MSSVs, and the low probability of an event occurring during this period that would require the ADV flowpath.

C.1 and C.2

If the ADV flowpaths cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance upon steam generator for heat removal, within 18 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the ADVs must be able to be opened locally and throttled through their full range. This SR ensures that the ADVs are capable of being locally operated by cycling the valve, with or without steam flow, at least once per fuel cycle. This test is in addition to the ASME quarterly inservice test required by 10 CFR 50.55a. The Frequency is considered acceptable based on engineering judgement and reliability.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.4.2

The function of the block valve is to isolate a failed open ADV. Cycling the block valve both closed and open, with or without steam flow, demonstrates its capability to perform this function. The Frequency is considered acceptable based on engineering judgement and reliability.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AFW System water and steam supply flow paths provides assurance that the proper flow paths will exist for AFW operation. This SR therefore also applies to Main Steam and Service Water valves located in these flowpaths. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The SR is modified by a Note that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The ~~31 day~~ Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by the ASME Code (Ref 2). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME Code (Ref. 2) (only required at 3 month intervals) satisfies this requirement.

This SR is modified by a Note indicating that performance of this SR for the turbine driven AFW pump is required to be completed within 24 hours after the unit exceeds 2% of RTP. This exception is required to prevent excessive RCS cooldowns as a result of steam draw from the steam generators during pump testing. This Note allows suitable test conditions to be established while allowing a reasonable time period to complete the SR during unit startups and low power operation.

SR 3.7.5.3

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an ESFAS, by demonstrating that the two motor driven AFW pump discharge flow control valves actuate to their correct positions on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under ~~administrative controls~~. The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The ~~18 month~~ Frequency is acceptable based on operating experience and the design reliability of the equipment.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that states one or more AFW pump systems may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.5.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal. The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

The ability of the Main Steam supply valves for the turbine driven pump to actuate to the correct position on an actual or simulated actuation signal is verified by this SR. The ability of the motor driven AFW pump discharge flow control valves to actuate to the correct position on an actual or simulated actuation signal is also tested by this SR.

This SR is modified by two Notes. Note 1 indicates that the SR may be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test. Note 2 states one or more AFW pump systems may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

SR 3.7.5.5

This SR verifies that the AFW is properly aligned by verifying the flow paths from the CST to each steam generator supplied by the respective AFW pump system prior to exceeding 2% of RTP after more than 30 days in any combination of MODE 5 or 6 or defueled. OPERABILITY of AFW flow paths must be verified before sufficient core heat is generated that would require the operation of the AFW System during a subsequent shutdown. The Frequency is reasonable, based on engineering judgement and other administrative controls that ensure that flow paths remain OPERABLE. To further ensure AFW System alignment, flow path OPERABILITY is verified following extended outages to determine no misalignment of valves has occurred. This SR ensures that the flow path from the CST to the steam generators is properly aligned.

BASES

ACTIONS (continued) B.1 and B.2

If the CST cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on the steam generator for heat removal, within 18 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that the CST contains the required volume of cooling water. The ~~12 hour~~ Frequency is based on operating experience and the need for operator awareness of unit evolutions that may affect the CST inventory between checks. Also, the ~~12 hour~~ Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal deviations in the CST level.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.6.1.A

This SR verifies the CST level is ≥ 21,150 gallons, when 2 CSTs are providing a passive flow of water to the Auxiliary Feedwater System of both units. The required volume is the same whether the two tanks are cross-tied or are individually aligned to each unit's Auxiliary Feedwater System.

SR 3.7.6.1.B

This SR verifies that the CST level is ≥ 35,837 gallons when 1 CST is providing a passive flow of water to the Auxiliary Feedwater Systems of both units.

SR 3.7.6.1.C

This SR verifies that the CST level is ≥ 14,100 gallons when 2 CSTs are providing a passive flow of water to the Auxiliary Feedwater System of one unit.

No changes - For Information only

BASES

ACTIONS (continued) B.1

If one required CC heat exchanger is inoperable (including inoperability of any associated piping, valves, and controls required to perform the safety related function that renders the heat exchanger inoperable), action must be taken to restore the inoperable heat exchanger to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CC heat exchanger is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE heat exchanger, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 144 hour Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which multiple Conditions are entered concurrently. The AND connector between 72 hour and 144 hour dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS SR 3.7.7.1

This SR is modified by a Note indicating that the isolation of the CC flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CC System.

Verifying the correct alignment for manual, power operated, and automatic valves in the CC flow path provides assurance that the proper flow paths exist for CC operation. This SR does not apply to

BASES

SURVEILLANCE REQUIREMENTS (continued)

valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The ~~31 day~~ Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

REFERENCES

1. FSAR. Section 9.1.

BASES

ACTIONS (continued)

G.1

If four or more SW pumps are inoperable, action must be taken within 1 hour to restore the SW pump(s) to OPERABLE status. The 1 hour Completion Time provides sufficient time to accommodate transitory operations (e.g. additional equipment inoperabilities, operations required to realign systems and equipment, etc;) to either restore the pump(s) to OPERABLE status or prepare for an orderly shutdown of the plant, and is commensurate with the importance of maintaining the SW System in an OPERABLE configuration.

H.1 and H.2

If the SW System cannot be restored to OPERABLE status within the associated Completion Times, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the SW System components or systems may render those components inoperable, but does not affect the OPERABILITY of the SW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the SW System flow path provides assurance that the proper flow paths exist for SW System operation. Included within the scope of this SR are the containment accident fan cooler isolation valves for the opposite unit. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The ~~31 day~~ Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.2

This SR verifies proper automatic operation of the SW System non-essential-SW-load isolation valves on an actual or simulated actuation signal. The SW System is a normally operating system that cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage 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 the Surveillance when performed at the ~~18 month~~ Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.8.3

This SR verifies proper automatic operation of the SW System pumps on an actual or simulated actuation signal. The SW System is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage 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 the Surveillance when performed at the ~~18 month~~ Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR. Section 9.6.
2. FSAR. Section 14.3.4.
3. FSAR. Section 9.2.
4. Technical Requirements Manual, TLCO 3.7.7, SW System
5. PBNP Calculation 2002-0003, Service Water System Design Basis

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, testing each fan subsystem once every month provides an adequate check of this system. Systems without heaters need only be operated for ≥ 15 minutes to demonstrate the function of the system. The ~~31 day~~ Frequency is based on the reliability of the equipment.

SR 3.7.9.2

This SR verifies that the required CREFS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.3

This SR verifies that each CREFS emergency and recirculation fan starts and operates on an actual or simulated actuation signal. The Frequency ~~of 18 months~~ is based on industry operating experience and is consistent with the typical refueling cycle.

SR 3.7.9.4

This SR verifies that each CREFS automatic damper in the emergency mode flow path will actuate to its required position on an actuation signal. The Frequency ~~of 18 months~~ is based on industry operating experience and is consistent with the typical refueling cycle.

SR 3.7.9.5

This test verifies manual actuation capability for CREFS. Manual actuation capability is required for OPERABILITY of the CREFS. The ~~18 month~~ Frequency is acceptable based on the inherent reliability of manual actuation circuits.

BASES

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the fuel storage pool, since the potential for a release of fission products exists.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the fuel storage pool water level is lower than the required level, the movement of irradiated fuel assemblies in the fuel storage pool is immediately suspended to a safe position. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

This SR verifies sufficient fuel storage pool water is available in the event of a fuel handling accident. The water level in the fuel storage pool must be checked periodically. The ~~7 day~~ Frequency is appropriate because the volume in the pool is normally stable. Water level changes are controlled by plant procedures and are acceptable based on operating experience.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

During refueling operations, the level in the fuel storage pool is in equilibrium with the refueling canal, and the level in the refueling cavity is checked daily in accordance with SR 3.9.6.1.

REFERENCES

1. FSAR, Section 9.4.
2. FSAR, Section 9.9.
3. FSAR, Section 14.2.1.
4. Regulatory Guide 1.183 (Rev. 0).
5. 10 CFR 50.67.

BASES

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies that the concentration of boron in the fuel storage pool is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The ~~7 day~~ Frequency is appropriate because no major replenishment of pool water is expected to take place over such a short period of time.

REFERENCES

1. FSAR. Section 9.4.
2. "Point Beach Units 1 and 2 Spent Fuel Pool Criticality Safety Analysis," WCAP-16541-P, Revision 2, Westinghouse Electric Company, June, 2008.
3. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).
4. FSAR. Section 14.2.1.
5. "Point Beach Units 1 and 2 Spent Fuel Pool Criticality Safety Analysis - Addendum, " WCAP-16541-NP, Revision 2, Addendum 1, Westinghouse Electric Company, November, 2009.

BASES

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity cannot be restored to within limits within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gross beta-gamma or gamma isotopic analysis of the secondary coolant, may be used to confirm DOSE EQUIVALENT I-131 is $\leq$ 0.1 μCi/gm. Confirmation of gross activity is a conservative means of determining compliance with the LCO limit. However, if gross activity exceeds the 1.0 μCi/gm limit, an isotopic analysis should be performed to determine DOSE EQUIVALENT I-131, to prevent unnecessary shutdowns. Performance of this SR confirms the validity of the safety analysis assumptions as to the secondary system source terms for post accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The 31 day Frequency is based on the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.67, Accident Source Term.
2. FSAR. Chapter 14.2.5.
3. Standard Review Plan, 15.0.1, Radiological Consequence Analyses Using Alternate Source Terms, Rev. 0, July 2000.

ACTIONS

A.1

When VNPAB is inoperable, action must be taken to restore the system to OPERABLE status within 7 days. The 7 day Completion Time is based on the low probability of a LOCA challenging control room habitability occurring during this period.

B.1 and B.2

If VNPAB cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

One filter and one stack fan are normally in operation. Standby fans should be checked periodically to ensure that they function properly. Proper functioning is confirmed through verification that the associated low flow lights for filter fans and for stack fans are not lit with one filter fan and one stack fan running. As the environment and normal operating conditions on this system are not severe, testing each fan subsystem once every month provides an adequate check of this system. Systems without heaters need only be operated for ≥ 15 minutes to demonstrate the function of the system. The ~~31 day~~ Frequency is based on the reliability of the equipment.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.14.2

This test verifies that the VNPAB system can maintain a PAB pressure less than atmospheric pressure and less than turbine building pressure. These pressure readings are periodically tested to verify proper functioning of the VNPAB system. The VNPAB system is designed to maintain a PAB pressure less than atmospheric pressure and less than turbine building pressure with one filter fan and one stack fan running. The ~~18 month~~ Frequency is acceptable based on the reliability of the equipment.

BASES

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.14.3

This test verifies manual actuation capability for VNPAB. Manual actuation capability is required for OPERABILITY of the VNPAB. The ~~18 month~~ Frequency is acceptable based on the reliability of manual actuation circuits.

REFERENCES

1. FSAR. Section 9.5.
2. FSAR. Section 14.3.5.

NRC SER, PBNP Units 1 and 2 - Issuance of License Amendments Regarding Use of Alternate Source Term, dated April 14, 2011.

SURVEILLANCE REQUIREMENTS (continued)

minimum plant design loading conditions. Minimum plant loading conditions at maximum grid limits (362 kV) will result in maximum voltage at the 4160 and 480 safety related buses. Motors are the most sensitive plant loads to high voltage. The maximum continuous operating design rating for safety related motors is 110% of nominal nameplate voltage as recommended by ANSI C50.41-1977. Therefore, under a worst case (minimum) design loading condition, electrical system voltages should be maintained low enough such that voltages at motor terminals remain below 110% of the motor nominal rating for continuous operation. It is permissible to operate motors above 110% for short duration, non-continuous operation when actual plant load conditions are higher than continuous operating conditions without causing damage or significantly reducing qualified motor life as stated in ANSI C84.1-1989. Continuous operation is defined as 24 hours per day per the NEC (National Electric Code). The maximum system voltage operating limits including instrument error should be maintained below 115% of nominal to ensure proper operation of all protective devices. This 115% limit is below the minimum 125% motor protective device setting limit from the NEC and is below the 119% limit listed in NUREG-1431 Rev. 2.

The safeguards distribution system frequency must be maintained within the limits allowed by connected equipment; below the setting of overcurrent relays; and above the setting of underfrequency relays. Electrical motors are sensitive to variations in operating frequency.

Equipment Technical Manuals for various 4160 V and 480 V motors have indicated motor terminal frequency must be maintained between 57 - 63 Hz, which is consistent with industry motor standards. The 57 - 63 Hz rating is also consistent with the allowable frequency ranges for other frequency sensitive non-motor loads (i.e., 480 V battery chargers). Although 63 Hz is the upper limit for motor operation to prevent motor damage, motors may not be capable of operating at 63 Hz due to circuit breaker settings. Since motor current increases with frequency, the possibility exists that circuit breakers supplying 480 V motors may trip on overcurrent if the 4160 V System is operated at elevated frequencies. Calculations performed verify that all safety related 480 V motors will not trip on overcurrent assuming their terminal frequency does not exceed 62.4 Hz. Therefore, to ensure that connected safety-related loads do not trip on overcurrent, 4160 V System frequency must not exceed 62.4 Hz.

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are

BASES

SURVEILLANCE REQUIREMENTS (continued)

connected to their preferred power source. The ~~7 day~~ Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.2

This SR helps to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, SR 3.8.1.2 is modified by a Note to indicate that all standby emergency power source starts for this surveillance may be preceded by an engine prelube and followed by a warmup period prior to loading.

For the purposes of SR 3.8.1.2 testing, the standby emergency power sources are started from standby conditions. Standby conditions for a standby emergency power source mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 3.8.1.2 requires that, at a 31 day Frequency, the standby emergency power source starts from standby conditions and achieves required voltage and frequency.

The ~~31 day~~ Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 4). This Frequency provides adequate assurance of standby emergency power source OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance verifies that the standby emergency power sources are capable of synchronizing with the offsite electrical system and accepting loads ≥ 2500 kW and ≤ 2850 kW. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the standby emergency power source is connected to the offsite source.

Although no power factor requirements are established by this SR, the standby emergency power source is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the standby emergency power source. Routine

BASES

SURVEILLANCE REQUIREMENTS (continued)

overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain standby emergency power source OPERABILITY.

The ~~31 day~~ Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 4).

This SR is modified by three Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients, because of changing bus loads, do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. Note 3 stipulates a prerequisite requirement for performance of this SR. A successful standby emergency power source start must precede this test to credit satisfactory performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.4

This Surveillance demonstrates that each required fuel oil transfer pump system operates and transfers fuel oil from its associated storage tank to its associated day tank and engine mounted sump as applicable. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer system is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The design of fuel transfer systems is such that pumps and valves operate automatically to maintain an adequate volume of fuel oil in the day and engine mounted sump tanks during or following standby emergency source testing.

The ~~31 day~~ Frequency is adequate to assure that the fuel oil transfer system is OPERABLE, since low level alarms are provided.

SR 3.8.1.5

In the event of a DBA coincident with a loss of offsite power, the standby emergency power sources are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the standby emergency power source operation, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the standby emergency power source. It further demonstrates the capability of the standby emergency power source to automatically achieve the required voltage and frequency within analysis limits.

The standby emergency power source autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the standby emergency power source loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or residual heat removal (RHR) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the standby emergency power source systems to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 18 months~~ is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 4), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with standard fuel cycle lengths.

For the purpose of this testing, the standby emergency power sources must be started from standby conditions. That is, with the engine oil continuously circulated and engine temperature maintained consistent with manufacturer recommendations for standby emergency power sources.

This SR is modified by a note. The reason for the Note is that the performance of the Surveillance would remove a required offsite source from service, perturb the electrical distribution system and challenge safety systems.

This restriction from normally performing the Surveillance in MODE 1, 2, 3 or 4 is further amplified to allow portions of the Surveillance to be

BASES

SURVEILLANCE REQUIREMENTS (continued)

performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, 3 or 4. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.6

As required by Regulatory Guide 1.9 (Ref. 4), this Surveillance ensures that the manual synchronization and load transfer from the standby emergency power source to the offsite source can be made and the standby emergency power source can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the standby emergency power source to reload if a subsequent loss of offsite power occurs. The standby emergency power source is considered to be in ready to load status when the standby emergency power source is at rated speed and voltage, the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequence timers are reset.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 18 months~~ is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 4), and takes into consideration unit conditions required to perform the Surveillance.

SR 3.8.1.7

This SR demonstrates ~~once per 18 months~~ that the standby emergency power sources can start and run continuously at full load capability.

The standby emergency power sources are tested at loads greater than the maximum expected design basis loading. The maximum design basis loading remains ≤ 2850 kW for Train A and ≤ 2848 kW for Train B.

The standby emergency power source starts for this Surveillance can be performed either from standby or hot conditions. The provisions for pre-lubricating and warmup, discusses in SR 3.8.1.2 and gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

BASES

APPLICABILITY (continued)

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

A.1 and A.2

An offsite circuit would be considered inoperable if it were not available to the safeguards buses required to be OPERABLE by LCO 3.8.10. Declaring the required features associated with an inoperable offsite circuit inoperable ensures that the appropriate restrictions are implemented in accordance with the affected supported features LCO Required Actions. The Completion Time of immediately is consistent with the required times for actions requiring prompt attention.

It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

B.1 and B.2

With the required standby emergency power source inoperable, the minimum required diversity of AC power sources is not available. Declaring the required features associated with the inoperable standby emergency power source inoperable ensures that the appropriate restrictions are implemented in accordance with the affected supported features LCO Required Actions. The Completion Time of immediately is consistent with the required times for actions requiring prompt attention.

It is further required to immediately initiate action to restore the required standby emergency power source to OPERABLE status. The restoration of the required standby emergency power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred offsite power source. The ~~7 day~~ Frequency

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.2.2

This SR helps to ensure the availability of the standby electrical power supply to mitigate DBAs and to maintain the unit in a safe shutdown condition.

To minimize wear on moving parts that do not get lubricated when the engine is not running, SR 3.8.2.2 is modified by a Note to indicate that all standby emergency power source starts for this Surveillance may be preceded by an engine prelube period and followed by a warmup period prior to loading.

SR 3.8.2.2 requires that, ~~at a 31 day Frequency,~~ the standby emergency power source starts from standby conditions and achieves required voltage and frequency. While not specifically stated within this SR, the standby emergency power source must be capable of starting and accepting loads.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This Frequency provides adequate assurance of standby emergency power source OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.2.3

This Surveillance demonstrates that each required fuel oil transfer system operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer system is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The design of fuel transfer systems is such that pumps and valves operate automatically in order to maintain an adequate volume of fuel oil in the day tanks during or following standby emergency source testing.

The ~~31 day~~ Frequency is adequate to assure that the fuel oil transfer system is OPERABLE, since low level alarms are provided.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.2.4

In the event of a loss of offsite power, the standby emergency power source is required to supply support systems necessary to avoid immediate difficulty, to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

This test verifies all actions encountered from a loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective connected loads from the standby emergency power source. It further demonstrates the capability of the standby emergency power source to automatically achieve the required voltage and frequency.

The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 18 months~~ is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 1), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with standard fuel cycle lengths.

For the purpose of this testing, the Standby emergency power sources must be started from standby conditions, that is, with the engine oil continuously circulated and engine temperature maintained consistent with manufacturer recommendations for standby emergency power sources.

This SR is modified by a note which exempts performance of this SR if the Frequency has expired. The standby emergency power source must continue to be capable of automatically starting and accepting loads; however, performance of the SR is not required if it is not met solely due to an expired frequency. The reason for the Note is to preclude requiring the OPERABLE standby emergency power source(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required 4160 V ESF bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the standby emergency power source. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the standby emergency power source and offsite circuit is required to be OPERABLE.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.2.5

As required by Regulatory Guide 1.9 (Ref. 1), this Surveillance ensures that the manual synchronization and automatic load transfer from the standby emergency power source to the offsite source can be made and the standby emergency power source can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the standby emergency power source to reload if a subsequent loss of offsite power occurs.

The standby emergency power source is considered to be in ready to load status when the standby emergency power source is at rated speed and voltage, the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequence logic is reset.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 18 months~~ is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 1), and takes into consideration unit conditions required to perform the Surveillance.

This SR is modified by a note which exempts performance of this SR if the Frequency has expired. The standby emergency power source must continue to be capable of synchronizing with offsite power and returning to a ready to load status, however performance of the SR is not required if it is not met solely due to an expired frequency. The reason for the Note is to preclude requiring the OPERABLE standby emergency power source(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required 4160 V ESF bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE.

REFERENCES

1. Regulatory Guide 1.9, Rev. 3, July 1993

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support operation of a single EDG for 6 days at full load. The 6 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location. The Surveillance Requirement is met when indicated level of each fuel oil storage tank is ≥ 86.2%, equal to approximately 32,100 usable gallons.

The ~~31 day~~ Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.2

The tests listed in the Diesel Fuel Oil Testing Program are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted in accordance with the Diesel Fuel Oil Testing Program.

The tests, limits and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-95 (Ref. 5);

b. Verify in accordance with the test specified in ASTM D1298-99 (Ref. 5) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API specific gravity at 60°F of ≥27° and ≤ 39°. Verify in accordance with tests specified in ASTM D975-98b (Ref. 6) a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flashpoint of ≥ 125°F; and

c. Verify that the new fuel oil has a clear and bright appearance when testing in accordance with ASTM D4176-91 (Ref. 5) and proper color in accordance with D1500-98.

BASES

SURVEILLANCE REQUIREMENTS (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 LCO concern since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel is analyzed to establish that the other properties specified in Table 1 for Grade Low Sulfur No. 2D of ASTM D975-98b (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-98b (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-95 (Ref. 5) or ASTM D 2622-98 (Ref. 5). The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

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.

Particulate concentrations should be determined in accordance with ASTM D6217-98, Method A (Ref. 5). This method involves gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/L. It is acceptable to obtain a field sample for subsequent laboratory testing.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.3

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each standby emergency power source is available. The system design requirements provide the capability to start and ready the standby emergency power source to accept load in 10 seconds from receipt of a start signal. The pressure specified in this SR is intended to reflect the lowest value at which the 10 second start can be accomplished. The Surveillance Requirement is met when indicated G01/G02 air bank pressures and indicated G03/G04 air bank pressures are ≥ 165 psig. The ~~31 day~~ Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.4

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks ~~once every 92 days~~ eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during standby emergency power source operation. Water may come from any of several sources, including condensation, ground water, rain water, and contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR. Section 8.8.
2. Regulatory Guide 1.137.
3. ANSI N195-1976, Appendix B.
4. FSAR, Chapter 14.
5. ASTM Standards: D4057-95; D1298-99; D4176-91; D1500-98; D1552-95; D2622-98; D6217-98, Method A.
6. ASTM Standards D975-98b, Table 1.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The ~~7 day~~ Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref. 6).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.2

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell, inter-rack, inter-tier, and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. The presence of visible corrosion does not necessarily represent a failure of this SR provided battery connection resistance is within limits.

The limits established for this SR must be no more than 20% above the resistance as measured during installation or not above the ceiling value established by the manufacturer.

These inspections

~~The Surveillance Frequency for these inspections, which can~~ detect conditions that can cause power losses due to resistance heating~~, is 92 days. This~~ Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

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SR 3.8.4.3

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The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

The ~~12 month~~ Frequency for this SR is consistent with IEEE-450 (Ref. 6), which recommends detailed visual inspection of cell condition and rack integrity on a yearly basis.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, inter-tier, and terminal connections provide an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anticorrosion material is used to help ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection. The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR provided visible corrosion is removed during performance of SR 3.8.4.4.

The connection resistance limits for SR 3.8.4.5 shall be no more than 20% above the resistance as measured during installation, or not above the ceiling value established by the manufacturer.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Surveillance Frequencies ~~of 12 months is~~ are consistent with IEEE-450 (Ref. 6), which recommends cell to cell and terminal connection resistance measurement on a yearly basis.

SR 3.8.4.6

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. 7), the battery charger supply is recommended to be based on the largest combined demands of the various steady-state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure~~s~~ that these requirements can be satisfied.

This SR provides two options. One option requires that battery chargers D-07, D-08, and D-09 be capable of supplying 320 amps at the minimum established float voltage for 8 hours, and battery chargers D-107, D-108, and D-109 be capable of supplying 420 amps at the minimum established float voltage for 8 hours. The ampere and voltage requirements are based on the design capacity of the chargers (Ref. 2). The ampere requirements coupled with the settings of the current limiters ensure that the chargers are able to supply the largest coincident demands of the various continuous steady-state loads and recharge the battery (283 amps), while staying within the capacity of the supply breakers. The nominal current limiter setpoints are 350 amps for battery chargers D-07, D-08, and D-09; and 450 amps for battery chargers D-107, D-108, and D-109. A setting band (340 - 355 amps and 440 - 460 amps respectively), based on these nominal values, is provided to allow for setting tolerances. The surveillance is performed

BASES

SURVEILLANCE REQUIREMENTS (continued)

by connecting sufficient resistive load to verify that the battery charger is operating at its as-left current limit setting without exceeding the supply breaker capacity even with increased loading. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

The other option requires that each battery charger be capable of recharging the battery after a service test, coincident with supplying the largest coincident demands of the various continuous steady-state loads (irrespective of the status of the plant during which these demands occur). This level of loading will be obtained using a resistance load bank. The duration for this test may be longer than the charger design capacity test discussed in the first option since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is ≤2 amps.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.7

A battery service test is a special test of battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to the design duty cycle requirements as specified in Reference 2.

The Surveillance Frequency ~~of 18 months~~ is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 7) and Regulatory Guide 1.129 (Ref. 8).

This SR is modified by a Note which allows the performance of a modified performance discharge test in lieu of a service test.

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

BASES

SURVEILLANCE REQUIREMENTS (continued)

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

A modified performance test is a test of battery capacity, with the discharge rates modified to encompass every portion of the battery duty cycle. This allows the performance test to be accomplished in the minimum amount of time while still demonstrating the high rate capability of the battery to meet the duty cycle requirements. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 6) and IEEE-485 (Ref. 3). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

~~The Surveillance Frequency for this test is normally 60 months.~~ If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 6), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 6).

BASES

ACTIONS (continued) not completing the Required Actions of Condition A within the required Completion Time or average electrolyte temperature of representative cells falling below 60°F, are also cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 2), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells.

SR 3.8.6.2

The ~~quarterly~~ inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 2). In addition, within 24 hours of a battery discharge < 105 V or a battery overcharge > 142.8 V, the battery must be demonstrated to meet Category B limits. Transients, such as motor starting transients, which may momentarily cause battery voltage to drop to ≤ 105 V, do not constitute a battery discharge provided the battery terminal voltage and float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 2), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells is > 60°F, is consistent with a recommendation of IEEE-450 (Ref. 2), that states that the temperature of electrolytes in representative cells should be determined on a quarterly basis.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer recommendations.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot

BASES

ACTIONS (continued) B.1 and B.2

If the inoperable inverter cannot be restored to OPERABLE status or the standby inverter placed into service within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital instrument buses energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the AC vital instrument buses. The ~~7 day~~ Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The TS surveillance voltage values are within industry standards for supply voltage and ensure adequate voltage to supplied components, including an allowance for voltage drop. The inverters regulate voltage within a narrow range for all expected DC supply voltage and inverter output loading conditions. The loads on the inverters do not vary significantly between normal and accident conditions.

The TS surveillance does not require verification of inverter frequency. Equipment design features and alarms for off-normal conditions ensure that adequate frequency is maintained. The inverters are normally in sync with offsite power and maintained a frequency of 60Hz. The inverters maintain a free running frequency of 60Hz+/- 0.5% or better. The original equipment specifications for Point Beach required +/-1% frequency regulation.

REFERENCES

1. FSAR. Chapter 8.6.
2. FSAR. Chapter 14.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital instrument buses energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation connected to the AC vital instrument buses. The ~~7 day~~ Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR. Chapter 14.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC vital instrument bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. For the 480 VAC buses B03 and B04, correct breaker alignment includes verification that the bus cross tie breakers are open with control power removed, when the system is not aligned in accordance with Note 1 or 2 of the LCO. This ensures the appropriate separation and independence of the electrical divisions is maintained. Correct breaker alignment provides assurance that the appropriate voltage is available to each required bus for motive as well as control functions for critical system loads.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The ~~7 day~~ Frequency takes into account the redundant capability of the AC, DC, and AC vital instrument bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR. Chapter 14.

BASES

ACTIONS (continued)

It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the units safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the required AC, DC, and AC vital instrument bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. For the 480 VAC buses B03 and B04, correct breaker alignment includes verification that the bus cross tie breakers are open, when the system is not aligned in accordance with the LCO Note. This ensures the appropriate separation and independence of the electrical divisions is maintained. For the vital instrument buses, correct breaker alignment shall include verification that the inverter static transfer switches are in their correct position, with the inverters supply power to their respective instrument buses. Correct breaker alignment provides assurance that the appropriate voltage is available to each required bus for motive as well as control functions for critical system loads.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The ~~7 day~~ Frequency takes into account the redundant capability of the AC, DC, and AC vital instrument bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR. Chapter 14

BASES

ACTIONS (continued)

concentration of any coolant volume in the RCS, the refueling canal, or the refueling cavity is less than its limit, all operations involving positive reactivity additions must be suspended immediately.

Suspension of positive reactivity additions shall not preclude moving a component to a safe position.

A.2

In addition to immediately suspending positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures that the coolant boron concentration in the RCS, the refueling canal, and the refueling cavity is within the COLR limits. The boron concentration is determined periodically by chemical analysis of a representative sample of the interconnected volumes.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This frequency

~~A minimum Frequency of once every 72 hours~~ is a reasonable amount of time to verify the boron concentration of representative samples. The Frequency is based on operating experience, which has shown ~~72 hours~~ to be adequate.

REFERENCES

1. FSAR. Sections 1.3.5, 3.1, and 9.3.
2. FSAR. Chapter 14.1.4.

BASES

ACTIONS (continued) C.1

With no audible count rate available, prompt and definite indication of a boron dilution event, consistent with the assumptions of the safety analysis is lost. In this situation the boron dilution event may not be detected quickly enough to assure sufficient time is available for operations to manually isolate the unborated water sources and stop the dilution prior to the loss of SHUTDOWN MARGIN. Therefore, action must be taken to prevent an inadvertent boron dilution event from occurring. This is accomplished by isolating all of the unborated water flow paths to the reactor coolant system. Isolating these flow paths ensures an inadvertent dilution of the reactor coolant boron concentration is prevented. The Completion Time of "Immediately" assures a prompt response by operations and requires an operator to initiate actions to isolate an affected flow path immediately. Once actions are initiated they must be continued until all the necessary flow paths are isolated or the circuit is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

SR 3.9.2.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Frequency ~~of 12 hours~~ is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.1.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.2.2

SR 3.9.2.2 is the performance of a CHANNEL CALIBRATION ~~every 18 months~~. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector plateau or preamp discriminator curves, ~~evaluating~~ those curves, and comparing the curves to the manufacturer's data. ~~The CHANNEL~~ CALIBRATION also includes verification of the audible count rate ~~function~~. The ~~18 month~~ Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed at the ~~18 month~~ Frequency.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open purge and exhaust valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment purge and exhaust isolation signal.

The Surveillance is performed ~~every 7 days~~ during movement of recently irradiated fuel assemblies within containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete fuel handling operations. A surveillance before the start of refueling operations will provide assurance that containment penetrations are in their required position during the applicable period for this LCO.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.3.2

This Surveillance demonstrates that each containment purge and exhaust valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal. The ~~18 month~~ Frequency maintains consistency with other similar ESFAS instrumentation and valve testing requirements. These Surveillances performed during MODE 6 will ensure that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the containment.

The SR is modified by a Note stating that this demonstration is not applicable to valves in isolated penetrations. LCO 3.9.3.c.1 provides the option to close penetrations in lieu of requiring automatic isolation capability.

REFERENCES

1. FSAR. Section 14.2.1.
2. Standard Review Plan (SRP) Section 15.0.1, Radiological Consequence Analyses Using Alternate Source Terms, Rev. 0, July 2000.
3. 10 CFR 50.67, Accident Source Term.
4. Regulatory Guide 1.183 (Rev. 0).
5. NRC Safety Evaluation for License Amendments 231/236, dated February 19, 2008

BASES

ACTIONS

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Note to the LCO.

A.1

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations.

A.2

If RHR loop requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition.

A.3

If RHR loop requirements are not met, actions shall be initiated and continued in order to satisfy RHR loop requirements. With the unit in MODE 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that the RHR loop is in operation and circulating reactor coolant. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing decay heat removal capability and mixing of the borated coolant to prevent thermal and boron stratification in the core. ~~The~~ Frequency ~~of 12 hours~~ is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the RHR System.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The

REFERENCES

1. FSAR. Section 9.2 and 14.1.4.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing decay heat removal capability and mixing of the borated coolant to prevent thermal and boron stratification in the core. In addition, during operation of the RHR loop with the water level in the vicinity of the reactor vessel nozzles, the RHR pump suction requirements must be met. The Frequency ~~of 12 hours~~ is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator for monitoring the RHR System in the control room.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.5.2

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency ~~of 7 days~~ is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. FSAR. Section 9.2 and 14.1.4

BASES

LCO

A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits, as provided by the guidance of Reference 1.

APPLICABILITY

LCO 3.9.6 is applicable when moving irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. LCO 3.9.3 provides additional requirements for movement of irradiated fuel assemblies within containment whose decay time is less then 65 hours. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.10, "Fuel Storage Pool Water Level."

ACTIONS

A.1

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Frequency ~~of 24 hours~~ is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely.

Attachment 5

NextEra Energy Point Peach, LLC
Point Beach Nuclear Plant

License Amendment Request No. 273
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 technical specifications (TS) surveillance frequencies to a licensee-controlled program. The proposed chage is described in Technical Specification Task Force (TSTF) Traveler, TSTF-425, Revision 3 (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 probabilisitic 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," (ML071360456).

Basis for proposed no significant hazards consideration:

As required by 10 CFR 50.91(a), the NextEra Energy Point Beech, LLC (NextEra) analysis of the issue of no significant hazards consideration is presented below:

1. Does the proposed change involve a significant increase in the probabaility 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 eveluated 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

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, NextEra 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.

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

Based upon the reasoning presented above, NextEra concludes that the requested change does not involve a significant hazards consideration as set forth in 10 CFR 50.92(c), Issuance of Amendment.