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NLS2016010
March 22, 2016

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

Subject: Application for Technical Specifications Change Regarding Risk-Informed Justification for the Relocation of Specific Surveillance Frequency Requirements to a Licensee Controlled Program
Cooper Nuclear Station, Docket No. 50-298, License No. DPR-46

Reference: Technical Specification Task Force Improved Standard Technical Specifications Change Traveler TSTF-425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control - RITSTF Initiative 5b," dated March 18, 2009

Dear Sir or Madam:

In accordance with the provisions of Title 10 of the Code of Federal Regulations (10 CFR 50.90), "Application for Amendment of License, Construction Permit, or Early Site Permit," Nebraska Public Power District (NPPD) is submitting a request for an amendment to the Technical Specifications (TS) for Cooper Nuclear Station (CNS). The proposed amendment would modify CNS TS by relocating specific surveillance frequencies to a licensee-controlled program with the implementation of Nuclear Energy Institute 04-10, "Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies."

The changes are consistent with Nuclear Regulatory Commission (NRC) approved Technical Specification Task Force Standard Technical Specifications Change TSTF-425, Revision 3 (Reference). The Federal Register notice published on July 6, 2009 (74 FR 31996), announced the availability of this TS improvement.

Attachment 1 provides a description of the proposed change, the requested confirmation of applicability, and plant-specific verifications. Attachment 2 provides documentation of Probabilistic Risk Assessment technical adequacy. Attachment 3 provides the existing TS pages marked up to show the proposed change. Attachment 4 provides revised (clean) TS pages. Attachment 5 provides the proposed TS Bases changes. Attachment 6 provides a TSTF-425 (NUREG-1433) versus CNS TS Cross-Reference. Attachment 7 provides the Proposed No Significant Hazards Consideration pursuant to 10 CFR 50.91(a)(1).

NPPD requests approval of the proposed license amendment by March 30, 2017, with the amendment being implemented within 60 days.

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NRR

This proposed TS change has been reviewed by the necessary safety review committees (Station Operations Review Committee and Safety Review and Audit Board). Amendments to the CNS Facility Operating License through Amendment 253 issued January 22, 2016, have been incorporated into this request. Pages 3.4-20 and 3.4-22 are affected by the license amendment request (LAR) to adopt a Pressure Temperature Limits Report currently under review by the NRC. That LAR was submitted August 6, 2015. This request is submitted under affirmation pursuant to 10 CFR 50.30(b).

By copy of this letter and its attachments, the appropriate State of Nebraska official is notified in accordance with 10 CFR 50.91(b)(1). Copies are also being provided to the NRC Region IV office and the CNS Senior Resident Inspector in accordance with 10 CFR 50.4(b)(1).

This letter contains no new regulatory commitments. Should you have any questions concerning this matter, please contact Jim Shaw, Licensing Manager, at (402) 825-2788.

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

Executed on: 3/22/16
(Date)

Sincerely,

Oscar A. Limpias
Vice President-Nuclear and Chief Nuclear Officer

/dv

Attachments:
1. Description and Assessment
2. Documentation of Probabilistic Risk Assessment Technical Adequacy
3. Proposed Technical Specification Changes (Markup)
4. Revised Technical Specification Pages (Re-Typed)
5. Proposed Technical Specification Bases Changes (Information Only)
6. TSTF-425 (NUREG-1433) versus CNS TS Cross-Reference
7. Proposed No Significant Hazards Consideration

cc: Regional Administrator w/attachments
USNRC - Region IV

Cooper Project Manager w/attachments
USNRC - NRR Plant Licensing Branch IV-2

Senior Resident Inspector w/attachments
USNRC - CNS

Nebraska Health and Human Services
Department of Regulation and Licensure
w/attachments

NPG Distribution w/o attachments

CNS Records w/attachments

Attachment 1

Description and Assessment

Cooper Nuclear Station, Docket No. 50-298, License No. DPR-46

Revised Pages

iv	3.3-26	3.4-26	3.6-29	3.8-18
1.1-5	3.3-27	3.5-3	3.6-30	3.8-23
3.1-10	3.3-30	3.5-4	3.6-32	3.8-24
3.1.13	3.3-36	3.5-5	3.6-33	3.8-27
3.1-17	3.3-45	3.5-6	3.6-35	3.8-30
3.1-19	3.3-50	3.5-9	3.6-39	3.9-2
3.1-21	3.3-55	3.5-10	3.6-42	3.9-3
3.1-22	3.3-56	3.5-12	3.7-2	3.9-4
3.1-26	3.3-59	3.5-13	3.7-4	3.9-7
3.2-1	3.3-62	3.6-2	3.7-5	3.9-8
3.2-2	3.3-65	3.6-7	3.7-7	3.9-11
3.2.4	3.3-68	3.6-12	3.7-10	3.9-14
3.3-3	3.4-3	3.6-13	3.7-12	3.10-5
3.3-4	3.4-5	3.6-14	3.7-13	3.10-8
3.3-5	3.4-7	3.6-15	3.7-15	3.10-12
3.3-11	3.4-9	3.6-16	3.8-5	3.10-14
3.3-12	3.4-11	3.6-17	3.8-6	3.10-15
3.3-16	3.4-13	3.6-19	3.8-7	3.10-17
3.3-17	3.4-16	3.6-21	3.8-8	3.10-22
3.3-18	3.4-18	3.6-22	3.8-9	3.10-23
3.3-21	3.4-20	3.6-24	3.8-15	5.0-18
3.3-24	3.4-22	3.6-26	3.8-17	5.0-19 (new)

The following pages are included due to repagination: 5.0-20, 5.0-21, 5.0-22, and 5.0-23

1.0 Description

2.0 Assessment

- 2.1 Applicability of Published Safety Evaluation
- 2.2 Optional Changes and Variations
- 2.3 Bases Changes

3.0 Regulatory Analysis

- 3.1 No Significant Hazards Consideration
- 3.2 Conclusion

4.0 Environmental Consideration

1.0 DESCRIPTION

This evaluation supports a request to amend Facility Operating License DPR-46 for Cooper Nuclear Station (CNS). The proposed amendment would modify Technical Specifications (TS) by relocating specific surveillance frequencies to a licensee-controlled program with the adoption of Technical Specification Task Force (TSTF) Traveler TSTF-425, Revision 3, "Relocate Surveillance Frequencies to Licensee Control - Risk Informed Technical Specification Task Force (RITSTF) Initiative 5b."

Additionally, the change would add a new program, the Surveillance Frequency Control Program (SFCP), to TS Section 5.0, Administrative Controls.

The changes are consistent with Nuclear Regulatory Commission (NRC) approved Industry/TSTF Standard Technical Specifications (STS) change TSTF-425, Revision 3, (ADAMS Accession No. ML090850642). The Federal Register notice published on July 6, 2009, announced the availability of this TS improvement.

Nebraska Public Power District (NPPD) requests approval of this LAR by March 30, 2017. Upon receipt of the approved amendment, CNS will implement the change within 60 days.

2.0 ASSESSMENT

2.1 Applicability of Published Safety Evaluation

NPPD has reviewed the safety evaluation dated July 6, 2009. This review included a review of the NRC staff's evaluation, TSTF-425, Revision 3, and the requirements specified in NEI 04-10, Revision 1, (ADAMS Accession No. ML071360456). Attachment 2 to this submittal includes CNS' documentation with regard to Probabilistic Risk Assessment (PRA) technical adequacy consistent with the requirements of Regulatory Guide 1.200, Revision 1 (ADAMS Accession No. ML070240001), Section 4.2, and describes any PRA models without NRC-endorsed standards, including documentation of the quality characteristics of those models in accordance with Regulatory Guide 1.200.

NPPD has concluded that the justifications presented in the TSTF proposal and the safety evaluation prepared by the NRC staff are applicable to CNS and justify this amendment to incorporate the changes to the CNS TS.

2.2 Optional Changes and Variations

The proposed amendment is consistent with the STS changes described in TSTF-425, Revision 3, with variations or deviations from TSTF-425, as identified below and may include differing TS Surveillance numbers.

2.2.1

The insert provided in TSTF-425 to replace text describing the basis for each frequency relocated to the SFCP has been revised from "The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program" to read "The Surveillance Frequency is controlled under the Surveillance Frequency Control Program." This deviation is consistent with NUREG-1433, Revision 4, with the NRC letter dated April 14, 2010 (ML100990099) and with the NRC supported changes to the letter in a subsequent discussion with the TSTF.

2.2.2

CNS Surveillances that have Surveillance numbers identical to the corresponding NUREG-1433 Surveillances are not deviations from TSTF-425. CNS Surveillance Requirements (SR) with Surveillance numbers that differ from the corresponding NUREG-1433 Surveillances are administrative deviations from TSTF-425 with no impact on the NRC staff's model safety evaluation dated July 6, 2009 (74 FR 31996).

For NUREG-1433 Surveillances that are not contained in the CNS TS, the corresponding NUREG-1433 mark-ups included in TSTF-425 for these Surveillances are not applicable to CNS. 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).

For CNS plant-specific Surveillances that are not contained in NUREG-1433, and therefore, are not included in the NUREG-1433 mark-ups provided in TSTF-425, NPPD has determined that the relocation of the Frequencies for these CNS plant-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, since the plant specific Surveillances involve fixed periodic Frequencies. In accordance with TSTF-425, changes to the Frequencies for these Surveillances would be controlled under the SFCP.

A cross-reference of the TSTF-425 Surveillance Requirements versus the CNS Surveillance Requirements is included in Attachment 6.

2.2.3

CNS TS SR 3.8.4.7, Note 1, is being revised to delete the frequency of "once per 60 months." This change is consistent with the latest revision of NUREG-1433. CNS TS SR 3.8.4.7 reflects the surveillance requirement of STS SR 3.8.4.3 which contains

a similar Note. However, the STS SR 3.8.4.3 Note 1 does not contain the reference to the Frequency of the modified performance discharge test. This change allows the modified performance discharge test in CNS TS SR 3.8.4.8 to be performed in lieu of the service test in CNS TS SR 3.8.4.7 at the Frequency established in the SFCP.

2.2.4

A correction to the format is being made on TS page 3.1-13. In the SR 3.1.4.4 FREQUENCY column, the word AND should be underlined.

2.3 Bases Changes

Revised TS Bases are provided in Attachment 5 for NRC information. These Bases revisions will be made as an implementing action pursuant to TS 5.5.10, TS Bases Control Program, following issuance of the amendment. The TS Bases for pages listed in Attachment 5 are revised by replacing frequency explanations with Note 2 that says, "The Surveillance Frequency is controlled under the Surveillance Frequency Control Program."

3.0 REGULATORY ANALYSIS

3.1 No Significant Hazards Consideration

NPPD has reviewed the proposed no significant hazards consideration determination (NSHC) published in the Federal Register on July 6, 2009 (74 FR 31996). NPPD has concluded that the proposed NSHC presented in the Federal Register notice is applicable to CNS and is provided as Attachment 7 to this amendment request which satisfies the requirement of 10 CFR 50.91(a).

3.2 Conclusion

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

4.0 ENVIRONMENTAL CONSIDERATION

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

Attachment 2

Documentation of Probabilistic Risk Assessment Technical Adequacy

Cooper Nuclear Station, Docket No. 50-298, License No. DPR-46

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Tables **Page**

Acronyms and Abbreviations

AS	Accident Sequence Analysis
ASME/ANS	American Society of Mechanical Engineers/American Nuclear Society
BWROG	Boiling Water Reactors Owners Group
BWR	Boiling Water Reactor
CNS	Cooper Nuclear Station
CDF	Core Damage Frequency
DA	Data Analysis
EPRI	Electric Power Research Institute
F&Os	Facts and Observations
HEP	Human Error Probability
HFE	Human Failure Event
HFO	High Winds, Floods, and Other External
HR	Human Reliability Analysis
IDP	Integrated Decision Making Panel
IE	Initiating Events Analysis
IF	Internal Flooding
IPEEE	Individual Plant Examination of External Events
LE	LERF Analysis
LERF	Large Early Release Frequency
MCR	Model Change Request
MSPI	Mitigating System Performance Index
MU	Maintenance and Update Process
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Assessment
PWR	Pressurized Water Reactor
QU	Quantification
SC	Success Criteria
SMA	Seismic Margins Analysis
SQUG	Seismic Qualification Users Group
SR	Supporting Requirement (of ASME Standard for PRA [Reference 5]
SRP	Standard Review Plan
SSCs	Systems, Structures and Components
STI	Surveillance Test Interval
SY	System Analysis

1.0 Overview

The implementation of the Surveillance Frequency Control Program (also referred to as Technical Specifications Initiative 5b) at CNS will follow the guidance provided in NEI 04-10, Revision 1 [Reference 1] in evaluating proposed surveillance test interval (STI; also referred to as "surveillance frequency") changes.

The following steps of the risk-informed STI revision process are common to the proposed changes to all STIs within the proposed licensee-controlled program.

- Each STI revision will be 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 would proceed. If a commitment exists and the commitment change process does not permit the change, then the STI revision would not be implemented.
- A qualitative analysis will be performed for each STI revision that involves several considerations as explained in NEI 04-10, Revision 1.
- Each STI revision will be reviewed by an Expert Panel, referred to as the Integrated Decision-Making Panel, which is similar to the Maintenance Rule implementation, which includes personnel with experience in surveillance tests and system or component reliability. If the IDP approves the STI revision, the change is documented and implemented, and available for audit by the NRC. If the IDP does not approve the STI revision, the STI value is left unchanged.
- Performance monitoring will be conducted as recommended by the IDP. In some cases, no additional monitoring may be necessary beyond that already conducted under the Maintenance Rule. The performance monitoring will help to confirm that no failure mechanisms related to the revised test interval become important enough to alter the information provided for the justification of the interval changes.
- The IDP will be 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 will return the STI back to the previously acceptable STI.
- In addition to the above steps, the Probabilistic Risk Assessment, also referred to as Probabilistic Safety Assessment, will be used when possible to quantify the effect of a proposed individual STI revision compared to acceptance criteria in NEI 04-10. Also, the cumulative impact of all risk-informed STI revisions on all PRAs (i.e., internal events, external events, and shutdown) is also compared to the risk acceptance criteria as delineated in NEI 04-10.

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 will be performed to provide justification for the acceptability of the proposed test interval change.

The NEI 04-10 methodology is consistent with the guidance provided in Regulatory Guide 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities" [Reference 2]. The guidance in Regulatory Guide 1.200 indicates that the following steps should be followed when performing PRA assessments (Note: Because of the broad scope of potential Initiative 5b applications and the fact that the risk assessment details will differ from application to application, each of the issues encompassed in Items 1 through 3 below will be covered in the PRA assessment made in support of the individual STI interval change requests. Item 3 satisfies one of the requirements of Section 4.2 of Regulatory Guide 1.200. The remaining requirements of Section 4.2 are addressed by Item 4 below):

1. Identify the parts of the PRA used to support the application
   - Systems, Structures and Components, operational characteristics affected by the application and how these are implemented in the PRA model
   - A definition of the acceptance criteria (e.g., change in CDF and LERF) used for the application
2. Identify the scope of risk contributors addressed by the PRA model
   - If not full scope (i.e., internal and external), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the model.
3. Summarize the risk assessment methodology used to address 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 the ASME standard endorsed by Regulatory Guide 1.200. 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.

The purpose of the remaining portion of this attachment is to address the requirements identified in Item 4 above.

2.0 Technical Adequacy of the PRA Model

The CNS PRA model is the most recent evaluation of the CNS risk profile for internal event challenges [Reference 3], and fire event challenges [Reference 15]. The CNS PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause failure events. The PRA model quantification process used for the CNS PRA is based on the event tree and fault tree methodology, which is a well-known methodology in the industry.

CNS employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models. This approach includes both a proceduralized PRA maintenance and update process, and the use of self-assessments and independent peer reviews. The following information describes this approach as it applies to the CNS PRA model.

PRA Maintenance and Update

The CNS risk management process ensures that the applicable PRA model is an accurate reflection of the as-built and as-operated plant. This process is defined in Procedure 3-EN-DC-151, "PSA Maintenance and Update." This procedure delineates the responsibilities and guidelines for updating the full power internal events PRA model. In addition, the procedure also stipulates use of PRA program implementing procedures that define the process for implementing regularly scheduled and interim PRA model updates, and for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, industry operating experience, etc.). To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plant, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model. Potential PRA model changes resulting from these reviews are entered into the MCR database, and a determination is made regarding the significance of the change with respect to current PRA model.
- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated approximately every four years, and
- Industry standards, experience, and technologies are periodically reviewed to ensure that any changes are appropriately incorporated into the models.

In addition, following each periodic PRA model update, a self-assessment is performed to assure that the PRA quality and expectations for all current applications are met. The CNS PRA maintenance and update procedure requires updating of all risk informed applications that may have been impacted by the update including but not limited to:

- System/component risk significance rankings
- PRA training materials
- Online Risk Model
- Mitigating System Performance Index input

2.1 Plant Changes Not Yet Incorporated into the CNS PRA Model

As part of the PRA evaluation for each STI change request, a review of open items in the MCR database for CNS will be performed and an assessment of the impact of the open items on the results of the PRA evaluation of the STI change request will be made prior to presenting the results of the risk analysis to the IDP. If the impact is not expected to be negligible, then this may include the performance of additional sensitivity studies or PRA model changes to confirm the impact on the risk analysis and justify why the change does not impact the PRA results used to support the application.

2.2 Regulatory Guide 1.200 BWROG Peer Review of the CNS PRA Model

2.2.1 Internal Events PRA Peer Review

The CNS PRA internal events model went through a Regulatory Guide 1.200 BWROG peer review in June of 2008. The NEI 05-04 process [Reference 4], the ASME/ANS PRA Standard [Reference 5], and Regulatory Guide 1.200, Rev. 1 [Reference 2] were used for the peer review.

The 2008 CNS Internal Events PRA Peer Review is documented in "Cooper Nuclear Station PRA Peer Review Report Using ASME PRA Standard Requirements" [Reference 6]. The peer review was a full-scope review of all the technical elements of the internal events, at-power PRA:

- Initiating Events Analysis (IE)
- Accident Sequence Analysis (AS)
- Success Criteria (SC)
- Systems Analysis (SY)
- Human Reliability Analysis (HR)
- Data Analysis (DA)
- Internal Flooding (IF)
- Quantification (QU)
- LERF Analysis (LE)
- Maintenance and Update Process (MU)

The CNS PRA Peer Review process uses capability categories to assess the relative technical merits and capabilities of each technical SR reviewed. Three capability category levels are used to indicate the relative quality level of each SR. Capability category assignments are made based on the judgment of the Peer Review Team after reviewing: (1) the PRA model, (2) the documentation; and, (3) the prior PRA Peer Review results (for historical background).

During the CNS PRA model Peer Review, the technical elements identified above were assessed with respect to Capability Category II criteria to better focus the SR assessments. The ASME/ANS PRA Standard has 331 individual SRs; 301 SRs are applicable to the CNS PRA model. Thirty (30) of the ASME/ANS PRA Standard SRs are not applicable to CNS (e.g., PWR related, multi-site related). The CNS PRA Model met the Capability Category II criteria for 289 of the 301 ASME/ANS

PRA Standard SRs. The F&Os for the CNS Internal Events PRA peer review are provided in Appendix B of the report, entitled, "Cooper Nuclear Station PRA Peer Review Report Using ASME PRA Standard Requirements" [Reference 6]. Of the 88 F&Os generated by the Peer Review Team, 22 were considered Findings, 57 were Suggestions, and 9 were Best Practices.

Subsequent to the resolution of the F&Os, a Maintenance Update of the CNS PRA Internal Events model was performed in 2014. As a part of this update, the CNS PRA Internal Events model was assessed against the requirements of Regulatory Guide 1.200, Rev. 2 [Reference 18]. This assessment included a Gap Analysis of the updated model against the requirements of Regulatory Guide 1.200, Rev. 2, and the results of the assessment are captured in the CNS PSA Notebooks. The assessment concluded that the CNS PRA meets or exceeds Capability Category II for all the SR over all of the PRA elements, and that all SR are met.

2.2.2 Fire PRA Peer Review

The CNS PRA fire events model went through Regulatory Guide 1.200 BWROG peer review that was completed in March of 2011. The NEI 07-12 process [Reference 16], the ASME/ANS PRA Standard [Reference 17], and Regulatory Guide 1.200, Rev. 2 [Reference 18]) were used for the peer review.

The 2011 CNS Fire Events PRA Peer Review is documented in "Cooper Nuclear Station Fire PRA Peer Review Report Using ASME PRA Standard Requirements" [Reference 19]. The peer review was a full-scope review of all of the technical elements of the CNS at-power Fire PRA against all technical elements in Section 4 of the ASME/ANS Combined PRA Standard, including the referenced internal events SRs in Section 2.

The CNS PRA Peer Review process uses capability categories to assess the relative technical merits and capabilities of each technical supporting requirement reviewed. Three capability category levels are used to indicate the relative quality level of each supporting requirement. Capability category assignments are made based on the judgment of the Peer Review Team after reviewing: (1) the PRA model, (2) the documentation; and, (3) the prior PRA Peer Review results (for historical background).

During the Fire CNS PRA model Peer Review, the technical elements identified above were assessed with respect to Capability Category II criteria to better focus the SR assessments. The ASME/ANS PRA Standard has 419 individual SRs; 337 SRs are applicable to the CNS PRA model. Eighty-two (82) of the ASME/ANS PRA Standard SRs are not applicable to CNS (e.g., PWR related, multi-site related). The CNS Fire PRA model met the Capability Category II criteria for 288 of the 337 ASME/ANS PRA Standard SRs. The F&Os for the CNS Fire Events PRA Peer Review are provided in Appendix B of the report, entitled, "Cooper Nuclear Station Fire PRA Peer Review Report Using ASME PRA Standard Requirements" [Reference 19]. Of the 116 F&Os generated by the Peer Review Team, 38 were considered Findings, 75 were Suggestions, and 3 were Best Practices.

2.3 Consistency with Applicable PRA Standards

2.3.1 Internal Events PRA Peer Review Consistency with Applicable PRA Standards

The Regulatory Guide 1.200 BWROG peer review [Reference 6] conclusions found that the CNS Internal Events PRA model met the Capability Category II or greater criteria for 289 of the 301 ASME Standard SRs. These conclusions resulted in gaps in 12 supporting requirement criteria detailed in 22 F&Os Findings requiring resolution when performing Capability Category II applications. Each of the 12 SRs found to not meet Capability Category II were addressed by CNS through resolution of the corresponding 22 Findings after completion of the peer review. None of these Findings are expected to impact the technical adequacy of the PRA for supporting the STI evaluations. Table 2-1 summarizes resolution of these 22 Findings. As can be seen, all the Findings have been closed. For each Finding in Table 2-1, CNS performed an evaluation of the expected impact on the STI evaluation application. It was found that none of the Findings would impact the STI evaluation application.

2.3.2 Fire PRA Peer Review Consistency with Applicable PRA Standards

The Regulatory Guide 1.200 BWROG peer review [Reference 19] conclusions found that the CNS Fire PRA Model met the Capability Category II or greater criteria for 288 of the 337 ASME Standard SRs. These conclusions resulted in gaps in 49 supporting requirement criteria. Each of the 49 SRs found to not meet Capability Category II were resolved by CNS. None of these 49 gaps are expected to impact the technical adequacy of the PRA for supporting the STI evaluations. Table 2-2 summarizes resolution of these 49 gaps. As can be seen, all of the gaps (Findings) have been closed. For each gap in Table 2-2, CNS performed an evaluation of the expected impact on the STI evaluation application. It was found that none of the gaps would impact the STI evaluation application.

2.4 Identification of Key Assumptions

The overall Initiative 5b process is a risk-informed process with the PRA model results providing one of the inputs to the IDP to determine if an STI change is warranted. The methodology recognizes that a key area of uncertainty for this application is the standby failure rate utilized in the determination of the STI extension impact. Therefore, the methodology requires the performance of selected sensitivity studies on the standby failure rate of the component(s) of interest for the STI assessment.

The results of the standby failure rate sensitivity study plus the results of any additional sensitivity studies identified during the performance of the reviews as outlined in 2.1 above (including a review of identified sources of uncertainty that were developed for CNS based on the NUREG 1855 [Reference 13] and complementary EPRI guidance [Reference 7]) will be documented for each STI change assessment and included in the results of the risk analysis that goes to the IDP.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
HR-G7	For multiple human actions in the same accident sequence or cut set, identified in accordance with supporting requirement QU-C1, ASSESS the degree of dependence, and calculate a joint human error probability that reflects the dependence. ACCOUNT for the influence of success or failure in preceding human actions and system performance on the human event under consideration including: *(a)* time required to complete all actions in relation to the time available to perform the actions *(b)* factors that could lead to dependence (e.g., common instrumentation, common procedures, increased stress, etc.) *(c)* availability of resources (e.g., personnel) [Note (1)]	SR not met. Dependencies between post-initiator actions have been accounted for in general and appear adequate. However, there are some dependencies which do not appear to have been evaluated (or at least documented). In particular, the use of two different "floors" for joint HEPs is a little questionable, as is its application. The Cooper HRA identifies cutsets with multiple HFEs and provides a method for assessing the degree of those dependencies. May want to consider using more recent dependency models. The Peer Review referred to the following five dependencies sets of examples: %FLSWRBM * FLD-XHE-FO-MSWRB * FLD-XHE-FO-SWRS1 * SWS-XHE-FO-SWNHP FPS-XHE-FO-RPVIN * HVC-XHE-FO-ALTQC ADS-XHE-FO-TRANS * HVC-XHE-FO-CB7A ECS-XHE-FO-TRANS * SWS-XHE-FO-SWBPS ADS-XHE-FO-3ALEG * SWS-XHE-FO-SWBPS	This finding has been addressed. Each of the identified human error probability (HEP) combinations identified by example in the finding was reexamined. These combinations of HEPs represent combinations of HEPs that were evaluated after the original dependent HEP cutset calculation. These were evaluated during the final model review and determined to be composed of independent HEPs that led to combined probabilities above or equal to the applicable floor. As a result, no additional dependent combinations were required to be developed and the PRA dependency evaluation was found acceptable with no model changes required.	The resolution of the Peer Review finding validated adequacy of the dependency evaluation and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
HR-I3	Document the key assumptions and key sources of uncertainty associated with the human reliability analysis.	SR not met. The Cooper PSA generally provides very detailed documentation, but, there is no discussion of sources of uncertainty regarding HRA consistent with the intent of SR HR-I3. Given the NRC sensitivity to the issue of sources of uncertainty (as evidenced by NRC Memorandum, "Notice of Clarification to Rev. 1 of Regulatory Guide 1.200", July 27, 2007, NRC ADAMS Accession number ML071170054), and the ASME Standard highlighting this specific issue in all Technical Elements, the intent of SR HR-I3 is judged not met by the current Cooper PSA documentation.	This finding has been addressed. Findings related to PRA base model uncertainty characterization have been resolved subsequent to the peer review. These peer review findings are identified as DA-E3-02, HR-13-01, IE-D3-01, IF-F3-01, and SC-C3-01. Resolution of the findings involved validation of the CNS PRA against applicable industry guidelines and required no changes to the PRA or the PRA documentation. Resolution was completed through validation that the guidance provided by NUREG-1855 and EPRI TR-1016737 was appropriately used to characterize the uncertainty relevant to the base CNS PRA. This guidance was in draft form during the Peer Review and therefore not available. The lack of final guidance on characterizing uncertainty in the base PRA model resulted in the CNS peer review findings in the supporting requirements subject to uncertainty evaluation.	The resolution of the Peer Review finding validated adequacy of documentation of the key assumptions and sources of uncertainty and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
IE-D3	Document the sources of model uncertainty and related assumptions (as identified in QU-E1 and QU-E2) associated with the initiating event analysis.	SR not met. The requirement is to document the key assumptions and key sources of uncertainty. The assumptions used for initiating events were scattered throughout the document (CNS PSA-001). Uncertainty bounds were established, but sources of uncertainty were not discussed.	This finding has been addressed. Findings related to PRA base model uncertainty characterization have been resolved subsequent to the Peer Review. These peer review findings are identified as DA-E3-02, HR-13-01, IE-D3-01, IF-F3-01, and SC-C3-01. Resolution of the findings involved validation of the CNS PRA against applicable industry guidelines and required no changes to the PRA or the PRA documentation. Resolution was completed through validation that the guidance provided by NUREG-1855 and EPRI TR-1016737 was appropriately used to characterize the uncertainty relevant to the base CNS PRA. This guidance was in draft form during the peer review and therefore not available. The lack of final guidance on characterizing uncertainty in the base PRA model resulted in the CNS peer review findings in the supporting requirements subject to uncertainty evaluation.	The resolution of the Peer Review finding validated adequacy of documentation of the key assumptions and sources of uncertainty and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
IF-B2	For each potential source of flooding, identify the flooding mechanisms that would result in a fluid release. Include: (a) failure modes of components such as pipes, tanks, gaskets, expansion joints, fittings, seals, etc. (b) human-induced mechanisms that could lead to overfilling tanks, diversion of flow through openings created to perform maintenance; inadvertent actuation of fire suppression system (c) other events resulting in a release into the flood area	SR not met. PSA-012 Appendix E identifies failure modes of pipes and components for each source. The components are not specifically identified, but are included in the totals. The only failure mode of components identified is rupture. Other failure modes are not discussed. Human induced floods are dismissed in section 2.2.9.1. The main argument is that the generic pipe rupture frequencies already included these types of failures. This seems reasonable for pipe and component ruptures; however it does not include other types of spill scenarios (such as tank overfills). It is likely that these types of releases can also be screened due to alarms or other process parameters, but it is not in the documentation. Maintenance induced spills are dismissed in part by saying that personnel are available to detect the spill because they are the ones doing maintenance. This probably covers most maintenance activities, but it is not necessarily true for operational events that are performed remotely.	This finding has been addressed. Subsequent to the PRA Peer Review, a supplemental evaluation was performed to estimate the potential contribution for human induced flooding. This evaluation concluded that the contribution of internal flooding events due to maintenance errors is quantitatively included in existing PRA quantifications.	The resolution of the Peer Review finding validated adequacy of identification of potential flooding sources and did not result in changes to the PRA model. Also, internal flooding events and modeling thereof do not impact fire risk. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
IF-F3	Document the key assumptions and key sources of uncertainty associated with the internal flooding analysis.	SR not met. Significant sources of uncertainty have been identified. However, there is a lack of treatment in the uncertainty analysis regarding modeling assumptions and structure. For internal flooding, this may involve the assumptions regarding doors terminating flood propagation or varying the flood target population. For these reasons this SR is "Not Met".	This finding has been addressed. Findings related to PRA base model uncertainty characterization have been resolved subsequent to the peer review. These peer review findings are identified as DA-E3-02, HR-13-01, IE-D3-01, IF-F3-01, and SC-C3-01. Resolution of the findings involved validation of the CNS PRA against applicable industry guidelines and required no changes to the PRA or the PRA documentation. Resolution was completed through validation that the guidance provided by NUREG-1855 and EPRI TR-1016737 was appropriately used to characterize the uncertainty relevant to the base CNS PRA. This guidance was in draft form during the Peer Review and therefore not available. The lack of final guidance on characterizing uncertainty in the base PRA model resulted in the CNS Peer Review findings in the supporting requirements subject to uncertainty evaluation.	The resolution of the Peer Review finding validated adequacy of documentation of the key assumptions and sources of uncertainty and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.
LE-G5	Identify limitations in the LERF analysis that would impact applications.	SR not met. There is a requirement to discuss limitations in the LERF analysis that would impact applications. This was performed in the Level 1 analysis, but there is no evidence in the Level 2 analysis of a limitations discussion.	This finding has been addressed. Assumptions associated with the containment event trees (CET) are summarized by the individual CET node in the applicable Appendix C section of the PRA Summary Notebook. These assumptions introduce the uncertainties that apply to the use of the Level 2 analysis. Furthermore, there are no limitations that would impact projected applications that are not identified as part of the uncertainty evaluation in the PRA Summary Notebook (Appendices A, B, E). Accordingly, no changes were made to the model.	The resolution of the Peer Review finding validated adequacy of the identification of limitations in the LERF analysis and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
MU-B2	PRA Configuration Control - Changes that would impact risk-informed decisions should be prioritized to ensure that the most significant changes are incorporated as soon as practical.	SR not met. CNS Procedure ESPD-13 (PSA Model Maintenance and Update Procedure) mentions examples of some applications that need to be addressed or updated. However, there is no discussion of prioritization or urgency. Prioritization seems to be focused on base model and future applications rather than past applications and risk-informed decisions. Also, a timetable should be established to state when the application impacts need to be incorporated (e.g., six months after the PSA update is officially released).	This finding has been addressed. Procedure (ESPD-13) was re-written to detail a new model maintenance and update process. The new process meets the requirements of the latest ASME PRA standard.	The resolution of the Peer Review finding validated adequacy of the revised model and maintenance update process and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.
MU-E1	The PRA configuration control process shall include a process for maintaining control of computer codes used to support PRA quantification.	SR not met. Software (including versions) should be specifically in SQA program, and the versions used should be consistent with the SQA program.	This finding has been addressed. The PRA configuration control procedure was revised to ensure that the software control procedures are now used to control PRA software.	The resolution of the Peer Review finding validated adequacy of the revised PRA configuration control process and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
MU-F1	The PRA configuration control process shall be documented. Documentation typically includes: (a) Description of the process used to monitor PRA inputs and collect new information (b) Evidence that the aforementioned process is active (c) Descriptions of proposed changes (d) Descriptions of changes in PRA due to each Update or Upgrade (e) Record of the performance and result of the appropriate PRA reviews (f) Record of the process and results used to address the cumulative impact of pending changes (g) Record of the process and results used to evaluate changes on previously implemented risk-informed decisions (pursuant to MU-D1) (h) Description of the process used to maintain software configuration control.	SR not met. Process exists to review past PRA applications and determine if an update to the risk informed application is required when the PRA model is updated. Cannot see evidence that the aforementioned process is active. List of applications is not up-to-date.	This finding has been addressed. The PRA configuration control procedure was revised to ensure that past PRA applications are identified and reviewed to ensure updates to the application are required.	The resolution of the Peer Review finding validated adequacy of the revised PRA configuration control process and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.
QU-F5	Document limitations in the quantification process that would impact applications.	SR not met. No discussion of limitations for applications in the documentation. A limitation is that not including IE fault trees in the main model yields incorrect importance measures for events/components in the IE fault tree. (QU-F5-01)	This finding has been addressed. The PRA Maintenance and Update procedure and application-specific guidelines have been revised to ensure limitations in the quantification are documented.	This finding has been resolved, and model update and application guidance has been updated. This will require the PRA applications including STI evaluations to address the IE fault trees separately as they are not integrated. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
IE-A7	Review plant-specific operating experience for initiating event precursors, for the purpose of identifying additional initiating events. For example, plant specific experience with intake structure clogging might indicate that loss of intake structures should be identified as a potential initiating event.	Capability Category I met. There is no evidence in the notebook that a precursor review was performed. Response to the question was Table 2.3-3 and LER review performed. The items in the table were all plant scrams. The LER review would contain non-scram precursors. However, a question was asked to the CNS team, and the response pointed back to the support system initiator development, which is covered by another SR. This SR of Category I (no requirement for precursor review).	This finding has been addressed. There was an extensive plant-specific review of operational experience to identify precursors. The systematic search for plant-unique and plant-specific support system initiators is documented in Section 2 of the initiating event notebook. The search for precursors included the interview of the system managers, operators, and a review of Cooper LERs. The Cooper Initiating Event notebook provides a detailed review of Cooper specific design and the identification of IE precursors; see Section 2.3 of CNS PSA-001. Each CNS specific system/subsystem) potential IE impact is discussed; for example, loss of steam tunnel and/or turbine building HVAC is discussed in Sections 2.3.3.20.1 and 2.3.3.20.2 as potential IE precursors as well as how each is handled. In addition, the PRA industry has exhaustively identified initiating event categories in countless IE studies over the past 30 years. Further, other SRs (e.g., IE-B3) already require individual support systems to be reviewed as potential initiating events. This is documented in Section 2 of the Initiating Event Notebook. In addition, the loss of intake initiating event was extensively studied. See Initiating Event Notebook Section 2 and Appendices C and J.	The resolution of the Peer Review finding validated adequacy of the initiating event analysis and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
QU-E3	Estimate the uncertainty interval of the overall CDF results. Estimate the uncertainty intervals associated with parameter uncertainties (DA-D3, HR-D6, HR-G9, IEC13), taking into account the "state-of-knowledge" correlation.	Capability Category I met. This is described in Appendix A of the Quantification Notebook. Type-code database deals with "state of knowledge" correlation. But, for many components with plant-specific data, even though there are multiple identical components with the same failure probability, type codes were not used. This means that the "state-of-knowledge" correlation is not correctly taken into account. Therefore, only Category 1 is met.	This finding has been addressed. The UNCERT database differs from the master basic event database. This is due primarily to the use of initial HEP values in the master basic event database set to higher values to ensure that low frequency cutsets are adequately "drawn in" to the cutsets, i.e., avoids premature truncation. These HEPs are subsequently reset to their nominal values by QRecover. As a result, the master basic event database does not reflect the basic events, distributions, and uncertainties used in the UNCERT model. Therefore, the master basic event database was not used for the UNCERT evaluation, but a modified database was used that includes: - Error factors and distributions for the dependent operator actions. - The "real" values of some basic events that are set to screening values and then replaced by the recovery file post quantification. This modified database for UNCERT was available and was used in the Cooper uncertainty calculations reported in the PRA, however, it was unintentionally omitted from the documents provided to the PRA Peer Review Team as part of their evaluation. It is concluded that, had this database been available for the peer team, the Capability Category II SR would have been met. There is no impact on applications or the base model.	The resolution of the Peer Review finding validated adequacy of the uncertainty analysis and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
AS-A2	For each modeled initiating event, identify the key safety functions that are necessary to reach a safe, stable state and prevent core damage.	Capability Category I/II/III met. Some event sequences are terminated when core damage has not occurred within 24 hours. In some, a stable state has not been reached based on the associated supporting thermal hydraulic calculation. For example, in 1A-L1-HPCI (which supports sequence GTR-002), containment temperature is still increasing at the end of 24 hours and has reached 250 °F. The operators will be directed to depressurize when temp reaches 280 °F. Another node appears to be needed in the tree to get to a stable state.	This finding has been addressed. The Peer Review characterization of CNS adherence to SR AS-A9 is documented to be "Met CC III", i.e. CNS use(s) realistic, plant specific thermal hydraulic analysis to determine the accident progression parameters (e.g., timing, temperature, pressure, steam) that could potentially affect operability of the mitigating systems". Additionally, the Peer Review characterized CNS adherence to SR AS-A2 as "Met" with documented significance of the finding being "The Class II sequences (which are known to be long term sequences) appear to have been evaluated appropriately". CNS review of the results of the referenced thermal-hydraulic calculation (1A-L1-HPCI) indicate that wet-well is trending downward starting at the 10th hour form the start of the postulated accident scenario, and drywell temperature peaking and starting to trend down at the 22nd hour. Hence it is not expected to see containment temperature to reach 280 °F. Based on the high marks received from the Peer Review on both SRs AS-A2 and AS-A9, the low significance of the finding as provided by the peer reviewers, and reexamination of the results of the example provided (i.e., MAAP run showed declining trends) , CNS sees no merit to further analysis.	The resolution of the Peer Review finding did not result in changes to the PRA model and hence the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
SC-B3	When defining success criteria, USE thermal/ hydraulic, structural, or other analyses/evaluations appropriate to the event being analyzed, and accounting for a level of detail consistent with the initiating event grouping (HLR-IE-B) and accident sequence modeling (HLR-AS-A and HLR-AS-B).	Capability Category I/II/III met. Appendix F of PSA-003 dismisses the need for long term core spray in large LOCA scenarios based on MAAP calculations. While consistent with existing PRAs, this needs to be addressed further. MAAP does not treat steaming in the low power bundles precisely. It is OK if recovery is imminent or if the core is going to a melt state, however for long term steady state at low water level it will over-predict the two phase level in the low power bundles. MAAP calculates an overall steaming rate and applies it evenly across all bundles. This provides an adequate collapsed level in each bundle, but the two-phase will be too high in the low power bundles. MAAP also does not behave as expected when calculating the individual node core power. Due to the way it handles the uranium group, the power shape calculated is flatter than expected. This could affect the two phase level as well.	This finding has been addressed. GE calculations are the basis for the success criteria – not relying solely on MAAP calculations. The success criteria that do not require core spray for large LOCA mitigation are based primarily upon GE calculations (NEDO 24708A, OG00-0170-062, and DRF-E22-00135-01). The Success Criteria Notebook in Appendix F identifies that the DBA calculations by GE do not show fuel or clad melting for the identified cases in question. Rather, the GE design calculations show that 10CFR50 App. K requirements for a DBA of < 17% clad oxidation cannot be assured. However, this is not a criterion for core damage as specified in the ASME PRA Standard or in the Cooper PRA. Therefore, these criteria do not need to be satisfied to allow success in the Level 1 PRA. The Cooper success criteria are consistent with all BWR PRAs reviewed under the BWROG Certification Program and NUREG-1150. The CNS success criteria are consistent with all boiling water reactor (BWR) PRAs reviewed under the BWROG certification program and NUREG-1150.	The resolution of the Peer Review finding determined that both GE analysis and MAAP were utilized in development of success criteria. Thus, no changes to the PRA model were required, and the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
SC-C3	Document the key assumptions and key sources of uncertainty associated with the development of success criteria.	Capability Category I/II/III met. It is possible that the success criteria uncertainty is addressed implicitly in the other elements; however the treatment of the uncertainty is characterized as an increase or decrease in reliability. Changes to success criteria would be a logic change and is more difficult to deal with in sensitivity analyses.	This finding has been addressed. Findings related to PRA base model uncertainty characterization have been resolved subsequent to the Peer Review. These Peer Review findings are identified as DA-E3-02, HR-13-01, IE-D3-01, IF-F3-01, and SC-C3-01. Resolution of the findings involved validation of the CNS PRA against applicable industry guidelines and required no changes to the PRA or the PRA documentation. Resolution was completed through validation that the guidance provided by NUREG-1 855 and EPRI TR-1016737 was appropriately used to characterize the uncertainty relevant to the base CNS. PRA. This guidance was in draft form during the peer review and therefore not available. The lack of final guidance on characterizing uncertainty in the base PRA model resulted in the CNS peer review findings in the supporting requirements subject to uncertainty evaluation.	The resolution of the Peer Review finding validated adequacy of documentation of the key assumptions and sources of uncertainty and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
SY-A4	Perform plant walkdowns and interviews with system engineers and plant operators to confirm that the systems analysis correctly reflects the as-built, as-operated plant.	Capability Category II/III met. IPE system notebook and internal flooding walkdowns are listed in the self-assessment as references for SR-A4. However, the IPE walkdowns were not recently performed and the internal flooding walkdowns were performed with different goals in mind. Also, operator interviews were conducted for the HRA analysis and accident sequence modeling, but were not performed for the system analysis and documented.	This finding has been addressed. There is no requirement in SR SY-A4 that system walkdowns be performed at each update. Numerous system walkdowns have been performed over the years in support of the CNS PRA and its applications. The value of the walkdowns and information gained must be balanced against the dose received performing the walkdowns. Some areas are inaccessible for routine walkdowns. The level of effort required to continually perform new walkdowns is inconsistent with the usefulness of such effort. Accordingly, no changes were made to the model.	The resolution of the Peer Review finding did not result in changes to the PRA model and hence the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
SY-A14	In meeting SY-A12 and SY-A13, contributors to system unavailability and unreliability (i.e., components and specific failure modes) may be excluded from the model if one of the following screening criteria is met: (a) A component may be excluded from the system model if the total failure probability of the component failure modes resulting in the same effect on system operation is at least two orders of magnitude lower than the highest failure probability of the other components in the same system train that results in the same effect on system operation. (b) One or more failure modes for a component may be excluded from the systems model if the contribution of them to the total failure rate or probability is less than 1% of the total failure rate or probability for that component, when their effects on system operation are the same.	Capability Category I/II/III met. SY-A13 imposes the requirement to explicitly include in the model failure modes such as "Fails to Remain Open/Closed". SA-A14 provides criteria for excluding these failures modes. The failure modes were generally excluded from the CNS system fault trees, but no documented assessment of criteria in SY-A14 was found.	The CNS PRA did use criteria detailed by this SR. Appendix B of the CNS PSA-010, Component Data Notebook, documents use of the requirements of SR SY-A15. These criteria were used in scoping component failure events for the PRA. Follow-up to this observation included update of the PRA notebooks to document the assessment of criteria contained in SY-A14.	The resolution of the Peer Review finding represents a documentation improvement for the model and hence the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
DA-E1	Document the data analysis in a manner that facilitates PRA applications, upgrades, and peer review.	Capability Category I/II/III met. The Maintenance Rule program processes and procedures and other plant data sources are relied upon to meet many of the aspects of the Data Analysis section. The processes that are used to screen and incorporate data collected in the Maintenance Rule program into the PRA plant specific data used in the model are not found in the PRA documentation.	This finding has been addressed. The basis for significance of this item is that the documentation doesn't facilitate peer review. Although addressing this item will help facilitate peer review, documentation issues such as this should be considered suggestions rather than findings. This documentation issue does not impact the technical adequacy of the PRA or its capability. PRA notebook CNS PSA-010, Component Data notebook provides the documentation for data analysis to ensure data bases are provided for users of the PRA. Use of maintenance rule data to assist in PRA data analysis are considered to be part of the skills sets for a PRA practitioner and not required to be documented as a process.	The resolution of the Peer Review finding did not result in changes to the PRA model and is representative of insights into the area of documentation of this SR. Hence the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
DA-E3	Document the key assumptions and key sources of uncertainty associated with the data analysis.	Capability Category I/II/III met. A source of uncertainty not treated relates to failure modeling for certain equipment failure modes. A normally open MOV, which is required to remain open, can spuriously close. This can happen during the 24-hr mission time after the initiator. It is also possible that it could happen during plant operation and not be detected. This should be discussed for all equipment failure modes that are modeled and which are subject to failure either prior to the initiator or after the initiator. Even though one or the other contribution to failure may be evaluated to be negligible, this should be addressed. The negligible contributor still makes a contribution to uncertainty.	This finding has been addressed. Findings related to PRA base model uncertainty characterization have been resolved subsequent to the Peer Review. These Peer Review findings are identified as DA-E3-02, HR-I3-01, IE-D3-01, IF-F3-01, and SC-C3-01. Resolution of the findings involved validation of the CNS PRA against applicable industry guidelines and required no changes to the PRA or the PRA documentation. Resolution was completed through validation that the guidance provided by the NUREG-1855 (issued subsequent to the peer review) and EPRI TR-1016737 was appropriately used to characterize the uncertainty relevant to the base CNS PRA. This guidance was in draft form during the peer review process and therefore not available. The lack of final guidance on characterizing uncertainty in the base PRA model resulted in the CNS Peer Review documenting findings in the supporting requirements subject to uncertainty evaluation.	The resolution of the Peer Review finding validated adequacy of documentation of the key assumptions and sources of uncertainty and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
HR-G6	CHECK the consistency of the post-initiator HEP quantifications. Review the HFEs and their final HEPs relative to each other to check their reasonableness given the scenario context, plant history, procedures, operational practices, and experience.	Capability Category I/II/III met. The HRA documentation mentions that the resulting HEPs were reviewed against each other. However, it isn't clear how this was done. For example, the HEP for the operator action to initiate drywell spray (RHR-XHE-FO-SPRAY) is about a factor of 3 times lower than the action to initiate torus cooling (RHR-XHE-FO-RHRE & RHR-XHEFO-RHRL). It's not obvious why this is logical given that the action to align torus cooling should be one of the most reliable actions given that it is performed fairly routinely (i.e., following any plant trip or manual shutdown). Also, according to the HRA calculator worksheets for these HFEs, the time available to align torus cooling is 886 minutes, while it's only 290 minutes for drywell spray. In addition, the operator action to perform emergency depressurization (ADS-XHE-FOTRANS) has a slightly lower HEP than the action to perform torus cooling, even though the time available for performing emergency depressurization is less than 30 minutes and under higher stress conditions.	This finding has been addressed. It is true that the initial HRA quantification of HEPs was performed by multiple analysts. However, once the initial analysis was completed, the results were independently reviewed by a senior analysis and review insights were incorporated into each of the HEP analysis. Subsequently, the final HEPs were developed and reviewed again for consistency and reasonableness. Each of the specific examples identified by this finding were reviewed and the HEP values used by the PRA were found consistent, reasonable and acceptable for use.	The resolution of the Peer Review finding did not result in changes to the PRA modeling of HEP and events. Hence the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
IF-B1	For each flood area, identify the potential sources of flooding [Note (1)]. Include: (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 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.).	Capability Category I/II/III met. Components evaluated as flood initiators should be specifically identified in PSA-012 Appendix E. The components should be identified similar to the way that the pipes are.	This finding has been addressed. The equipment that could be sources of flooding in each area are identified in the Walkdown Sheets located in the Internal Flood Walkdown Notebook. Identification in the walkdown sheets and inclusion in the internal flood walkdown notebook documents that components were evaluated and included as required.	The resolution of the Peer Review finding did not result in changes to the PRA model and hence the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-1 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Internal Events PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
QU-D4	Review a sampling of no significant accident cutsets or sequences to determine they are reasonable and have physical meaning.	Capability Category I/II/III met. Could not find evidence of review of non-significant cutsets to determine if they are reasonable. Documentation is available that shows review of high level cutsets (top 100-200).	This finding has been addressed. No documentation requirement exists in the ASME PRA Standard for this item. It appears that the review team is interpreting that detailed write-ups are required for every detailed step taken in the development of the PRA. The subject review of non-significant cutsets was performed multiple times during draft quantifications of the model, as well as the final documented dominant sequence and cutset discussions in the PRA Summary Notebook. The PRA does not maintain hand mark-ups of draft quantifications and associated fixes. The peer review team recommendation for detailed write-ups of more cutsets and sequences, and write-ups of hand mark-ups and corrections in draft quantifications is judged by NPPD to be beyond the intent of this SR. Reviews done by the PRA modelers during development and quantification is deemed adequate for this SR.	The resolution of the Peer Review finding did not result in changes to the PRA model and hence the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
SY-A2	Collect pertinent information to ensure that the systems analysis appropriately reflects the as-built and as-operated systems. Examples of such information include system P&IDs, one-line diagrams, instrumentation and control drawings, spatial layout drawings, system operating procedures, abnormal operating procedures, emergency procedures, success criteria calculations, the final or updated SAR, technical specifications, training information, system descriptions and related design documents, actual system operating experience, and interviews with system engineers and operators.	CNS PRM report NEDC 09-079, Rev. 0, Section 4.2.4 includes some discussion on system models. The internal events PRA fault trees were modified to include the failure modes caused by fires and to add ISLOCA pathways, and IORVs caused by spurious component operation. In addition, the fault trees, while sufficient for use in the internal events PRA, were enhanced to ensure they were sufficient to meet the needs of the fire PRA as well. Significant system model changes have been implemented. However, the documentation is not sufficient for review with respect to the pertinent information listed in SR SY-A2 and other SY SRs. Moreover, the feedwater system model is significantly enhanced in the fire model, which would be appropriate to update the internal events system model to capture all the updated information. As a result, SY-A2 is considered not met.	Calculation NEDC 09-079, "Risk Model Development," provides a list of references used in the development of system modeling, and NEDC 09-078, "Fire PRA Component Selection," lists references used in the component selection process. The references provide the pertinent information referred to by this supporting requirement or point to sources of where this information can be located. References include post-fire response procedures and other operating procedures that represent the as-operated plant. Additionally, the Fire PRA MS Access Database is referenced which includes the SAP Database ID. The SAP Database is a CNS-specific database that contains the details of applicable as-built resources such as P&IDs, I&C drawings, and other information important for supporting a sufficient review of the criteria for this supporting requirement. The Fire PRA database is an electronic document that is controlled in the same way as the Internal Events PRA Model (CAFTA Model). As noted in the review, the Feedwater system modeling was enhanced to support Fire PRA modeling.	Actions taken to resolve the Peer Review Finding ensured system analysis appropriately reflected as-operated systems. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
SY-A3	Review plant information sources to define or establish: (a) system components and boundaries (b) dependencies on other systems (c) instrumentation and control requirements (d) testing and maintenance requirements and practices (e) operating limitations such as those imposed by Technical	See SY-A2 assessment.	Fire PRA modeling was performed in a manner that maintained the integrity of the Internal Events Model and allows for proper evaluation of both the Internal Events PRA and the Fire PRA. The Internal Events Model is documented separately and was evaluated under the Internal Events Peer Review. The information in SR SY-A3 does not have to be recreated in the development of the Fire PRA Model. However, new components and fire-induced impacts should be considered. The new components are listed in NEDC 09-079.	Actions taken to resolve the Peer Review Finding ensured system analysis appropriately reflected as-operated systems. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
	Specifications (f) component operability and design limits (g) procedures for the operation of the system during normal and accident conditions (h) system configuration during normal and accident conditions		Applicable plant information, such as post-fire operating procedures are referenced in the Fire PRA supporting calculations for component selection (NEDC 09-078), Fire PRA model development (NEDC 09-079), and (NEDC 09-083) Fire Human Reliability Analysis. Additionally, the Fire PRA MS Access Database is referenced by these calculations which include the SAP Database ID. The SAP Database is a CNS-specific database that contains the details of applicable as-built resources such as P&IDs, I&C drawings, and other information germane to allowing a sufficient review of the criteria for this supporting requirement.	
SY-A4	Perform plant walkdowns and interviews with knowledgeable plant personnel (e.g., engineering, plant operations, etc.) to confirm that the systems analysis correctly reflects the as-built, as-operated plant.	See SY-A2 assessment.	The Fire PRA was developed using the CNS Internal Events PRA. Plant walkdowns were performed; however, this was not performed explicitly for SSC review for system analysis, but rather for fire modeling. Licensed operators were interviewed for HRA, and others (licensed operators, system engineers, etc.) were part of an Expert Panel convened for analysis of multiple spurious operation. No changes were made in the Fire PRA model that would invalidate internal events systems analyses or the walkdown and interview results.	Disposition of this Peer Review Finding ensured system analysis appropriately reflected as-operated systems. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
SY-A6	In defining the system model boundary [see SY-A3], include within the boundary the components required for system operation, and the components providing the interfaces with support systems required for actuation and operation of the system components.	The system boundary may be changed due to the updates to the system models in fire PRA, such as the feedwater system model. The addition of instruments may also require the updates to the system boundaries. SY-A6 is considered not met.	The system boundary is defined in the Internal Events documentation which was not revised for Fire PRA modeling. Fire PRA documentation; Calculation NEDC 09-079 was completed to provide identification of new components added to the model.	Disposition of this Peer Review Finding ensured system analysis appropriately reflected as-operated systems. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
SY-A12	Do not include in a system model component failures that would be beneficial to system operation, unless omission would distort the results. Example of a beneficial failure: A failure of an instrument in such a fashion as to generate a required actuation signal.	Some fire impacts are inappropriately modeled crediting beneficial failures. See F&O 4-12 for details. As a result, SY A12 is considered not met.	In accordance with NEDC 09-079, Section 4.4, "...if a passive failure will place a component in an acceptable configuration, modeling is not included because the spurious operation would be similar to modeling a failure as a success." Furthermore the calculation states: "Failures that place components in a successful position are not modeled in the fault tree logic." In regard to the reviewer's example of where this was overlooked, SRV logic in the Fire PRA fault tree has been rebuilt, and nested NOTs have been reviewed and revised, as needed.	Disposition of this Peer Review Finding ensured that the system analysis appropriately precluded system modeling from crediting beneficial failures. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
SY-A24	Do not model the repair of hardware faults, unless the probability of repair is justified through an adequate analysis or examination of data.	Followed internal events model. However, repairs modeled in internal events have not been evaluated for fire PRA model. See SPC-XHE-FO-RCVR, SWS-XHE-FO-RCVR in F&O 4-11.	Table 4-4 was updated to Table 4 of NEDC 09-083, "Task 7.12 Fire Human Reliability Analysis," and these specific repairs modeled in internal events no longer apply and have been removed from Table 4. Disposition of HFEs noted: SPC-XHE-FO-RCVR & SWS-XHE-FO-RCVR - Internal events values are set to 1.0 (always failed). The HEP of 1.0 is retained for the Fire PRA. The Fire PRA did include repair of battery chargers and diesel generator fuel oil transfer pumps. These repairs are included in the fire response procedures, have the needed parts and equipment pre-staged, and include timing assessments. A detailed human reliability analysis was performed to determine the HEP. The fire scenarios were further reviewed and additional detailed analysis was performed. This included not only detailed fire modeling and fire human reliability analysis, but also detailed circuit analysis and circuit failure likelihood analysis.	Disposition of this Peer Review Finding ensured that the modeling of repairs are justified through adequate analysis. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
SY-C1	Document the systems analysis in a manner that facilitates PRA applications, upgrades, and peer review.	Significant system model changes have been implemented. However, the documentation is not sufficient for review with respect to the pertinent information listed in SR SY-A2 and other SY SRs. As a result, SY-C1 is considered not met.	Calculation NEDC 09-079, "Risk Model Development" describes how the Fire PRA Model was developed and lists the files that document the modeling. The fault tree modifications implemented as part of the Fire PRA are documented in the Fire PRA Database which is an electronic document that will be controlled in the same way the Internal Events PRA Model (CAFTA Model) is controlled. The Fire PRA Database provides the details necessary	Disposition of this Peer Review Finding ensured that the system analysis is documented through calculations and modeling databases. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
			for reviewing the Fire PRA system analysis. Specific information includes a detailed description of the fault tree enhancements made to the Internal Events Model, and cross-referenced to the SAP Location. The SAP Database is a CNS-specific database that contains the details of applicable as-built resources such as P&IDs, I&C drawings, and other information germane to allowing a sufficient review of the criteria listed in SR SY-A2 and other SRs. Therefore, the logic used for Fire PRA modeling is documented in the Fire PRA calculation.	
SY-C2	Document the system functions and boundary, the associated success criteria, the modeled components and failure modes including human actions, and a description of modeled dependencies including support system and common cause failures, including the inputs, methods, and results. For example, this documentation typically includes: (a) system function and operation under normal and emergency operations (b) system model boundary (c) system schematic illustrating all equipment and components necessary for system operation (d) information and calculations to support equipment operability considerations and assumptions (e) actual operational history indicating any past problems in the system operation (f) system success criteria and relationship to accident sequence models (g) human actions necessary for operation of system (h) reference to system-related	Significant system model changes have been implemented. However, the documentation is not sufficient for review with respect to the pertinent information listed in SR SY-A2 and other SY SRs. As a result, SY-C2 is considered not met.	Calculation NEDC 09-079, "Fire Induced Risk Model," documents the process and changes made to develop the Fire PRA Model. Aspects of the types of documentation listed in SY-C2 that differ for Fire PRA Modeling, as compared to Internal Events Modeling, are defined and documented in the Fire PRA Documentation. For example, nomenclature used in Fire PRA Modeling is defined in Section B.2 of NEDC 09-079. Fire PRA Modeling does not represent a change to the Internal Events Model; therefore, it is appropriately not included in the Internal Events documentation. Human failure events (HFEs) added to the Fire PRA Model to represent post-fire human actions are documented by calculation NEDC 09-083, "Fire Human Reliability Analysis."	Disposition of this Peer Review Finding ensured that the system analysis is documented through calculations and modeling databases. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
	test and maintenance procedures (i) system dependencies and shared component interface (j) component spatial information (k) assumptions or simplifications made in development of the system models (l) the components and failure modes included in the model and justification for any exclusion of components and failure modes (m) a description of the modularization process (if used) (n) records of resolution of logic loops developed during fault tree linking (if used) (o) results of the system model evaluations (p) results of sensitivity studies (if used) (q) the sources of the above information (e.g., completed checklist from walkdowns, notes from discussions with plant personnel) (r) basic events in the system fault trees so that they are traceable to modules and to cutsets (s) the nomenclature used in the system models			

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
SY-C3	Document the sources of model uncertainty and related assumptions (as identified in QU-E1 and QUE2) associated with the systems analysis.	Significant system model changes have been implemented. However, the documentation is not sufficient for review with respect to the pertinent information listed in SR SY-A2 and other SY SRs. Additionally, plant specific uncertainty due to PRA model changes is not discussed in Table 5 of the uncertainty analysis. As a result, SY-C3 is considered not met.	The Fire PRA system analyses are documented in calculation NEDC 09-079, "Risk Model Development." Calculation NEDC 09-086, "Uncertainty and Sensitivity," provides a summary of assumptions and uncertainties from NEDC 09-079. NEDC 09-079 addresses F&O associated with this task. An expanded discussion was added on assumptions and uncertainties to explicitly address this supporting requirement.	Disposition of this Peer Review Finding ensured that uncertainty is documented through calculations and modeling databases. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
HR-G7	For multiple human actions in the same accident sequence or cut set, identified in accordance with supporting requirement QU-C1, assess the degree of dependence, and calculate a joint human error probability that reflects the dependence. Account for the influence of success or failure in preceding human actions and system performance on the human event under consideration including (a) time required to complete all actions in relation to the time available to perform the actions (b) factors that could lead to dependence (e.g., common instrumentation, common procedures, increased stress, etc.) (c) availability of resources (e.g., personnel)	Based on the review of draft model files, CNS methodology cannot meet HR-H3 and QU-C1 requirements for the dependencies among multiple HFEs that potentially impact significant accident sequences/cutsets. The current quantification method does not use higher HEP values in quantification and does not apply recovery file that includes HEP combination events. As a result, HR-G7 is considered not met.	Dependency Analysis was completed in NEDC 09-083, "Task 7.12 Human Reliability Analysis," and is summarized in NEDC 09-085, "Task 7.14 Fire Risk Quantification," as follows: Dependencies among operator actions exist for any of the following parameters that may have a common effect on operator actions including timing, procedures, cues, personnel, and staffing resources. Dependencies arise from post-initiator human error events that may be linked in the quantification process. If these operator actions are not independent, then any sequence cutsets associated with two or more of these dependent operator actions would be incorrect. The dependency analysis was performed in Task 7.12 using the EPRI HRA Calculator. The dependencies were identified and examined in the analysis by identifying combinations of operator actions and then determining their level of dependence.	Disposition of this Peer Review Finding ensured that dependencies for human error events were identified and evaluated. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
HR-H3	Account for any dependency between the HFE for operator recovery and any other HFEs in the sequence, scenario, or cutset to which the recovery is applied (see HR-G7).	Based on the review of draft model files, CNS methodology cannot meet HR-H3 and QU-C1 requirements for the dependencies among multiple HFEs that potentially impact significant accident sequences/cutsets. The current quantification method does not use higher HEP values in quantification and does not apply recovery file that includes HEP combination events.	Dependency Analysis was completed in NEDC 09-083, "Task 7.12 Human Reliability Analysis," and is summarized in NEDC 09-085, "Task 7.14 Fire Risk Quantification," as follows: Dependencies among operator actions exist for any of the following parameters that may have a common effect on operator actions including timing, procedures, cues, personnel, and staffing resources. Dependencies arise from post-initiator human error events that may be linked in the quantification process. If these operator actions are not independent, then any sequence cutsets associated with two or more of these dependent operator actions would be incorrect. The dependency analysis was performed in Task 7.12 using the EPRI HRA Calculator. The dependencies were identified and examined in the analysis by identifying combinations of operator actions and then determining their level of dependence.	Disposition of this Peer Review Finding ensured that dependencies for human error events were identified and evaluated. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
DA-C2	Collect plant-specific data for the basic event/parameter grouping corresponding to that defined by requirement DA-A1, DA-A3, DA-A4, DA-B1, and DA-B2.	The majority of component failure probability values, excluding spurious operation, do not need reanalysis for the Fire PRA. However, a query of BE table in the CNSONE.RR database shows that several events with a style of 'fire' may be added in the fire models and require DA reanalysis: CRD-SOV-CC-SO140A, CRD-SOV-CC-SO140B, LCS-CKV-LK-18CV, LCS-CKV-LK-19CV, RCI-CKV-LK-18CV, RCI-CKV-LK-19CV, RHR-CKV-LK-26CV, RHR-CKV-LK-27CV. As a result, PRM-B12 and B13 are considered not met. Check valve leakage can be uncovered through surveillance.	With respect to new components added to support Fire PRA modeling; basic event/parameter grouping is from recognized industry sources such as NUREG/CR-6928, "Industry-average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants." The basic event Type Codes were established independent of the Fire PRA Model; therefore, no data reanalysis is necessary.	Disposition of this Peer Review Finding found that data used in the fire PRA has sound basis form industry sources of the CNS internal events PRA. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
DA-C3	Collect plant-specific data, in a manner consistent with uniformity in design, operational practices, and experience. Justify the rationale for screening or disregarding plant-specific data (e.g., plant design modifications, changes in operating practices).	See PRM-B13.	With respect to new components added to support Fire PRA modeling; basic event/parameter grouping is from recognized industry sources such as NUREG/CR-6928, "Industry-average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants." The basic event Type Codes were established independent of the Fire PRA Model; therefore, no data reanalysis is necessary.	Disposition of this Peer Review Finding found that data used in the fire PRA has sound basis form industry sources of the CNS internal events PRA. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
DA-C9	Estimate operational time from surveillance test practices for standby components, and from actual operational data.	See PRM-B13.	With respect to new components added to support Fire PRA modeling; basic event/parameter grouping is from recognized industry sources such as NUREG/CR-6928, "Industry-average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants." The basic event Type Codes were established independent of the Fire PRA Model; therefore, no data reanalysis is necessary.	Disposition of this Peer Review Finding found that data used in the fire PRA has sound basis form industry sources of the CNS internal events PRA. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
DA-C10	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 operations.	See PRM-B13.	With respect to new components added to support Fire PRA modeling; basic event/parameter grouping is from recognized industry sources such as NUREG/CR-6928, "Industry-average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants." The basic event Type Codes were established independent of the Fire PRA Model; therefore, no data reanalysis is necessary.	Disposition of this Peer Review Finding found that data used in the fire PRA has sound basis form industry sources of the CNS internal events PRA. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
DA-D8	If modifications to plant design or operating practice lead to a condition where past data are no longer representative of current performance, limit the use of old data: (a) If the modification involves new equipment or a practice where generic parameter estimates are available, use the generic parameter estimates updated with plant-specific data as it becomes available for	See PRM-B13.	With respect to new components added to support Fire PRA modeling; basic event/parameter grouping is from recognized industry sources such as NUREG/CR-6928, "Industry-average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants." The basic event Type Codes were established independent of the Fire PRA Model; therefore, no data reanalysis is necessary.	Disposition of this Peer Review Finding found that data used in the fire PRA has sound basis form industry sources of the CNS internal events PRA. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
	unique design or operational features; or (b) If the modification is unique to the extent that generic parameter estimates are not available and only limited experience is available following the change, then analyze the impact of the change and assess the hypothetical effect on the historical data to determine to what extent the data can be used.			
DA-E1	Document the data analysis in a manner that facilitates PRA applications, upgrades, and peer review.	No documentation of data analysis for basic events added in fire PRA model.	With respect to new components added to support Fire PRA modeling; basic event/parameter grouping is from recognized industry sources such as NUREG/CR-6928, "Industry-average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants." The basic event Type Codes were established independent of the Fire PRA Model; therefore, no data reanalysis is necessary.	Disposition of this Peer Review Finding found that data used in the fire PRA has sound basis form industry sources of the CNS internal events PRA. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
DA-E3	Document the sources of model uncertainty and related assumptions (as identified in QU-E1 and QUE2) associated with the data analysis.	No documentation of data analysis for basic events added in fire PRA model.	With respect to new components added to support Fire PRA modeling; basic event/parameter grouping is from recognized industry sources such as NUREG/CR-6928, "Industry-average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants." The basic event Type Codes were established independent of the Fire PRA Model; therefore, no data reanalysis is necessary.	Disposition of this Peer Review Finding found that data used in the fire PRA has sound basis form industry sources of the CNS internal events PRA. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
QU-E3	Estimate the uncertainty interval of the CDF results. Estimate the uncertainty intervals associated with parameter uncertainties (DA-D3, HR-D6, HR-G8, IE-C15), taking into account the state-of-knowledge correlation.	No quantitative estimate of CDF/LERF uncertainty intervals was performed for CNS.	Calculation NEDC-09-086, "Task 7.15 Uncertainty and Sensitivity Analysis," which was the basis for the peer review, provides the uncertainty and sensitivity analyses. The following summarizes the philosophy for addressing the uncertainty quantitatively used in the calculation: From Section 1, A complete, quantitative analysis of uncertainties and assumptions is not conducted. This is, for the most part, consistent with the PRA Standard and referenced guidance documents, and is consistent with	Disposition of this Peer Review Finding provided uncertainty interval estimates. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
			prevailing good practices. The focus is on a qualitative characterization. Where appropriate sensitivity evaluations will be conducted when applying the FPRA. Table 3, in Section 6 discusses the approach to addressing parameter uncertainties. From the conclusions (Section 8), the results of this task are used to support integrated decision making. As has been noted, a quantitative characterization has not been developed as the quantitative results are conservatively biased for key contributors. A better estimate of the mean value for CDF and LERF is estimated to be a factor of 5 to 10 lower than calculated with a 90 percentile range of a factor of 10 on the lower end and 5 on the higher end. Relevant uncertainties will be addressed in the use of the FPRA. The major conservatisms are believed to be fire ignition frequency and the development and progression of a fire. Both increase the calculated frequency of core damage and large early release. Generic fire frequencies are directly based on assumptions in NUREG/CR-6850 (including FAQ-48 enhancements) estimating the severity and applicability of fires from incomplete fire event reports which lack critical information in the Fire Events Database. In the absence of complete data, the ignition frequencies remain conservative based on fires being assumed to be challenging fires, event duration being assumed the same as the actual fire duration, and lack of detailed damage information. These incomplete fire events provide the basis for the probability of non-suppression values for manual fire fighting. Additionally, the assumptions involving the growth and propagation of a fire including non-realistic peak heat release rates, cable flame spread rates, and cable tray propagation rule sets directly lead to reduction in effectiveness of detection/suppression, and time available for operator action. Given the significant contributors to calculated results, the modeling and quantification of human reliability also can influence the results considerably. This occurs because for many of the significant sequences safe shutdown requires use of alternate shutdown which can involve many coordinated actions, and in some sequences with limited time margin for accomplishing the actions. State-of-the-art methods	

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
			have been used but there is the potential for central tendency of the results to be either optimistic or pessimistic. The conservatism in fire growth time is expected to more than offset the potential for optimistic results to significantly influence calculated results." Attachment A to the calculation documents the approach for each related supporting requirement in the Standard. **Discussion:** As noted, an estimate of the uncertainty interval was provided. However, the peer review team finding is related to the technical basis for this estimate and that each of the technical areas contributing to this estimate was not explicitly addressed. Thus the following is provided: The start of the Fire PRA CDF and LERF calculations are the FDS and associated frequencies. More than 800 FDS were developed; combined with the cut-sets associated with each FDS, more than 100,000 sequences at the cut-set level were developed. The FDS include the ignition frequency and severity factor, detection and suppression conditional probabilities, and the fire modeling needed to develop these conditional probabilities. The cut-sets address data (DA), human reliability (HR), and circuit failure (CF). The DA parameter uncertainties are addressed in the Internal Events PRA and are directly relevant to the Fire PRA. As noted in the calculation, "A better estimate of the mean value for CDF and LERF is estimated to be a factor of 5 to 10 lower than calculated with a 90 percentile range of a factor of 10 on the lower end and 5 on the higher end. Relevant uncertainties will be addressed in the use of the FPRA. The major conservatisms are believed to be fire ignition frequency and the development and progression of a fire. Both increase the calculated frequency of core damage and large early release."	

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
			To support this estimate, consider as typical for a sequence which results in core damage or large early release: The Ignition Frequency uncertainties range factor is on the order of 10 based on NUREG/CR-6850. The estimated conditional probability of an FDS, given a fire ignition, has an uncertainty range factor on the order of 10 on the low side and 5 on the high side, based on judgment (includes fire development and propagation, and detection and suppression). The range factor for DA can be approximated by a factor of 3 to 5 based on the Internal Events PRA and typical uncertainties associated with unavailability and failure rates in recognition that the actual parameter uncertainty depends on the specific cut-sets. The range factor for HR can be approximated by a factor of 3 to 5 based on the HRA calculation. The range factor for CF can be approximated by a factor of 4 on the low side and 2 on the high side based on NUREG/CR-6850. The uncertainty on large early release given a core damage end state has a range factor, again on average, on the order of 3 to 5 based on the Internal Events PRA and other PRA studies. Thus, typical significant CDF sequences can be represented by: CDF1 (where a random failure must occur after the FDS is reached, such as RCIC fails to start) = Ignition Frequency ("-10/+10") * Conditional FDS frequency ("-10/+5") * DA ("-5/+5") CDF2 (where a human error must occur after the FDS is reached, such as failure to realign a valve after inadvertent operation of the valve due to a spurious signal causes flow diversion) = Ignition Frequency ("-10/+10") * Conditional FDS probability ("-10/+5") * Conditional CF likelihood probability ("-4/+2") * HR	

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
			failure probability ("-5/+5") Thus, as provided in the calculation, a reasonable estimate of the uncertainty interval is minus 10 to plus 5 on the calculated mean value, where the mean is estimated to be on the order of a factor of 5 to 10 lower than calculated.	
LE-C7	In crediting HFEs that support the accident progression analysis, use the applicable requirements of 2-2.5 as appropriate for the level of detail of the analysis.	Although there is no changes specific for fire, the existing HFEs should be evaluated in the context of fire.	NEDC 09-079, "Task 7.5 Fire-Induced Risk Model," Attachment F is the Level 2 Human Failure Events Review. Those HFEs that are not post-fire operator actions have been denoted as such. Those that are post-fire operator actions make reference to NEDC 09-083, "Task 7.12 Fire Human Reliability Analysis." All Attachment F HFEs were reviewed and LERF HFEs were verified to be included in the HRA report, NEDC 09-083.	Disposition of this Peer Review Finding provided documentation of evaluation of HFEs for fire events. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
PRM-B9	For any cases where new system models or split fractions are needed, or existing models or split fractions need to be modified to include fire-induced equipment failures, fire-specific operator actions, and/or spurious actuations, perform the systems analysis portion of the Fire PRA model in accordance with HLR-SY-A and HLR-SY-B and their SRs in Section 2 with the following clarifications, and develop a defined basis to support the claim of non-applicability of any of these requirements in Section 2: • All the SRs under HLR-SY-A and HLR-SY-B in Section 2 are to be addressed in the context of fire scenarios including effects on system operability/functionality accounting for fire damage to	CNS system model changes in the fire PRA models are summarized in multiple reports. However, these changes are considered as temporary until the final quantification is complete. A number of supporting requirements under SY-A (SYA2, 3, 4, 6, 12, and 24) are not met as a result. Therefore, PRM-B9 is considered not met. See F&Os 1-15, 2-3, 2-6, 2-13, 4-5, 4-11, and 4-12 for more details.	CNS system model changes in the Fire PRA models are summarized in multiple reports and these changes are now considered as final with the final quantification now complete. The purpose of NEDC 09-079 "Task 7.5 Fire-Induced Risk Model" was to develop a risk logic model to enable identification and quantification of all CDF and LERF sequences that could result from a fire initiating event. The internal events model was used as the foundation for the Fire PRA model. The Fire PRA model includes fire-induced impacts on the systems, trains, and components modeled in the internal events fault tree logic. Fire PRA modeling was performed in a manner that maintains the integrity of the internal events fault tree model and allows for proper evaluation of both the Internal Events PRA and the Fire PRA. To evaluate internal events, the fire initiators are all set to the default value of 0.0 and fire events are set to either 0.0 or 1.0 depending on how they input to their parent gate. For example, if a fire event is under an "OR" gate, it would be set to 0.0 for the internal events cases. PRAQuant solves each fire scenario by setting all internal events initiators to 0.0 and setting fire initiators and those basic events representing components impacted by the	Disposition of this Peer Review Finding ensured that final documentation of CNS system model changes in the fire PRA are provided . Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
	equipment and associated cabling.		fire to 1.0. As such, Fire PRA modeling does not represent a change to the internal events modeling and appropriately is not included in the internal events documentation (e.g., system notebooks). Fire-induced failures (or new components) and supporting fault tree logic such as a check-valve internal leakage (ISLOCA logic), spurious operations, and/or new failure modes not included in the internal events modeling are documented in NEDC 09-079 "Task 7.5 Fire-Induced Risk Model", Attachment D "New Components and New Random Failure Modes Added to Support Fire PRA." The Fire PRA model considers the impact of a fire on active and passive failures. For each active failure, a corresponding fire-induced failure is modeled. If a passive failure (i.e., a spurious operation) could place the component in an undesirable configuration, the passive failure is modeled as well. However, if a passive failure places a component in an acceptable configuration, modeling is not included because the spurious operation would be similar to modeling a "failure" as a "success." For example, for a valve Fails-To-Close in the internal events model; the fire model would have a corresponding, Fails-To-Close Due-To-Fire basic event. There would not be a passive failure (Spurious Close) for this valve in this branch of the fault tree, as the success position is "closed." The fire scenarios were further reviewed and additional detailed analysis was performed. This included not only detailed fire modeling and fire human reliability analysis, but also detailed circuit analysis and circuit failure likelihood analysis. The post-fire human reliability analysis considers operator actions (human failure events) as needed for safe-shutdown, including those called out in relevant fire response procedures. The post-fire human actions added to the Fire PRA model include the human performance shaping factors associated with a fire and are not applicable to an internal events non-fire initiator.	

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
PRM-B11	Model all operator actions and operator influences in accordance with the HRA element of this standard.	CNS Calculation NEDC 09-083 (Scientech Calculation 17712-003) describes the operator actions included in the model. Included in the documentation are those internal events operator actions not credited in the Fire PRA and the additional human actions from CNS Procedure 5.4POST-FIRE included in the Fire PRA. The HRA Calculator was used to determine the HEPs for both existing internal events human actions and new fire response human actions. NEDC 09-078 R0 (Scientech Calc 17712-001), FIRE PRA COMPONENT SELECTION, Attachments E and F include a review of instrumentation and Manual Action Review, which covers the operator interface dependencies across systems or trains, where applicable. However, the Level 2 HFEs were not evaluated adequately. See F&Os 4-9 and 4-10 for more details. As a result, PRM-B11 is considered not met.	NEDC-09-083, "Task 7.12 Fire Human Reliability Analysis," describes the operator actions included in the model. Included in the documentation are those internal events operator actions not credited in the Fire PRA and the additional human actions from CNS Procedure 5.4POST-FIRE included in the Fire PRA. The HRA Calculator was used to determine the HEPs for both existing internal events human actions and new fire response human actions. NEDC 09-078, "Tasks 7.2 Component Selection," Attachments E and F include a review of instrumentation and Manual Action Review, which covers the operator interface dependencies across systems or trains, where applicable. Existing EOP operator actions were identified from a review of the Internal Events HRA analysis. The fire impacts due to fire damage to instrumentation are identified as part of NEDC 09-078, "Tasks 7.2 Component Selection," and NEDC 09-075, "Task 7.3 Cable Selection/Location." For any existing operator action where the instrumentation cables were not traced the HFE was set to 1.0. It was assumed that these instruments would be unavailable for every fire and with no instrumentation available for diagnosis the HEP is 1.0. Table 5 in NEDC-09-083, "Task 7.12 Fire Human Reliability Analysis," shows the HFEs retained in the Fire PRA and the instrumentation required for diagnosis for each HFE. NEDC 09-079, "Task 7.5 Fire-Induced Risk Model," Attachment E (Attachment F in latest revision), is the Level 2 Human Failure Events Review. Those HFEs that are not post-fire operator actions have been denoted as such. Those that are post-fire operator actions make reference to NEDC 09-083, "Task 7.12 Fire Human Reliability Analysis." The four HFEs identified in F&O 4-9 are not in the HRA report because they are Level 2 events, not LERF events. All Attachment F HFEs were reviewed and LERF HFEs were verified to be included in the HRA report, NEDC 09-083.	Disposition of this Peer Review Finding provided documentation of evaluation of LERF HFEs for fire events. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
PRM-B13	For any item identified per PRM-B12, perform the data analysis portion of the Fire PRA plant response model in accordance with HLR-DA-A, HLR-DA-B, HLR-DA-C, and HLR-DA-D and their SRs in Section 2 with the following clarifications: a) All the SRs under HLR-DA-A, HLR-DA-B, HLR-DA-C, and HLR-DA-D in Section 2 are to be addressed in the context of both random events as well as fire events causing damage to equipment and associated cabling, and b) develop a defined basis to support the claim of non-applicability of any of these requirements in Section 2	This refers to component failure probabilities. Based on the CNS self assessment, no component failure probability values, excluding spurious operation, needed reanalysis for the Fire PRA. However, a query of BE table in the cnsone.rr database shows that several events with a style of 'fire' may be added in the fire models and require DA reanalysis: CRD-SOVCC-SO140A, CRD-SOV-CC-SO140B, LCS-CKV-LK-18CV, LCS-CKV-LK-19CV, RCI-CKV-LK-18CV, RCI-CKV-LK-19CV, RHRCKV-LK-26CV, RHR-CKV-LK-27CV, EAC-DG1-OVERLOAD, EAC-DG2-OVERLOAD. On the other hand, the expanded feedwater model and other additional system model changes for the fire PRA models may warrant more DA reanalysis. Human error probabilities were re-evaluated given a fire in Task 7.12 Calculation NEDC 09-083 (Scientech Calculation 17712-003). Spurious operations probabilities are documented in Task 7.10 Calculation NEDC 09-082 (Scientech Calculation 17712-007). PRM-B12 is considered met because the basic events were identified and B13 is considered not met because the data reanalysis was not performed.	NEDC 09-079, "Risk Model Development," documents new components and new failure modes that were added to the Fire PRA Model. Each new component and/or new failure mode was reviewed for System Analysis and/or Data Analysis, as appropriate to assess supporting level requirements. Component random failure probabilities use the values existing in the Internal Events parameter file. The new basic events evaluated are not fire-induced failures; therefore, the values used in the quantification of the Fire PRA Model are appropriate. Regarding other Fire PRA Modeling changes such as fire-induced spurious operations and other fire-induced failures, the data was taken from NUREG/CR-6850 and fire initiator frequencies, respectively. As such, no data reanalysis is warranted.	Disposition of this Peer Review Finding found that data used in the fire PRA has sound basis form industry sources of the CNS internal events PRA. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
FSS-A4	Identify one or more combinations of target sets for each unscreened physical analysis unit such that the credible range of system and function impacts has been represented.	EPM-DP-FP-001 Rev. 1 provides the methodology for target identification. Target damage sets are provided in each fire compartment/zone detailed fire modeling calc (NEDC 09-091 through NEDC 09-101). Target damage sets for compartments modeled as full room burnout are provided in FPRA Level 1 failure report. However, a review of the top cutsets indicates there are opportunities for improvement. For example, the 3B and 3A zone failure evaluations would benefit from creating fire scenarios which would save the bus duct for the emergency transformer and in the case of 3B the cross power cables.	Detailed fire modeling calculations have been developed for all fire zones deemed risk significant which include Fire Zones 3A (NEDC 10-046), 3B (NEDC 10-047), 8E (NEDC 10-043), 8F (NEDC 10-049), 8H (NEDC 10-043), 14A (NEDC 10-044), 14B (NEDC 10-045), and 13A (NEDC 09-095). These updates made to the Fire PRA in response to fire PRA peer review F&O 2-21 and 4-18 have incorporated combinations of target sets for each of these unscreened risk significant areas.	Disposition of this Peer Review Finding resulted in use of detail fire modeling where appropriate. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
FSS-A5	For each unscreened physical analysis unit, select one or more combinations of a fire ignition source (or group of ignition sources) as defined in SR FSS-A1 and a target set (or group of target sets) as defined in SR FSS-A4 as characteristics of the selected fire scenarios that will provide reasonable assurance that the fire risk contribution of each unscreened physical analysis unit can be characterized.	EPM-DP-FP-001 Rev. 1 provides the methodology for target identification. Target damage sets are documented in each fire compartment/zone detailed fire modeling calc (NEDC 09-091 through NEDC 09-101). However, a review of the top cutsets indicates there are opportunities for improvement. For example, the 3B and 3A zone failure evaluations would benefit from creating fire scenarios which would save the bus duct for the emergency transformer and in the case of 3B the cross power cables.	Detailed fire modeling calculations have been developed for all fire zones deemed risk significant which include Fire Zones 3A (NEDC 10-046), 3B (NEDC 10-047), 8E (NEDC 10-043), 8F (NEDC 10-049), 8H (NEDC 10-043), 14A (NEDC 10-044), 14B (NEDC 10-045), and 13A (NEDC 09-095). These updates made to the Fire PRA in response to fire PRA peer review F&O 4-18 have incorporated combinations of target sets and combinations of ignition sources for each of these unscreened risk significant areas, and this SR is now considered to meet Cat I/II.	Disposition of this Peer Review Finding resulted in use of detail fire modeling where appropriate. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
FSS-D1	Select appropriate fire modeling tools for estimating fire growth and damage behavior considering the physical behaviors relevant to the selected fire scenarios.	The fire modeling tools selected are addressed in CNS documents R1906-711-01, R1906-07-011b-001, and EPM-DPFP-001. The fire modeling tools are adequate when used within their limitations. However, there are no specific limits beyond which the output from the fire modeling tools become invalid. Two cases where this arises is with hot gas layer effects coupled with localized fire exposure effects (plume-layer/thermal radiation-layer) and when the postulated flame height exceeds the ceiling height. In the latter case, the radiant heat flux model would be invalid. The smoke detection model appears to be critical for application of the severity factor and non-suppression probabilities; however, this model has not been through a formal verification and validation process.	Updates made to the Fire PRA in response to fire PRA peer review F&Os 3-1, 3-9, 3-12, and 3-13 justify that the appropriate fire modeling tools are used within their limitations through a formal verification and validation process.	Disposition of this Peer Review Finding resulted in ensuring appropriate fire modeling verification and validation processes were performed. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
FSS-D2	Use fire models that have sufficient capability to model the conditions of interest and only within known limits of applicability.	CNS documents R1906-711-01, R1906-07-011b-001, and EPM-DP-FP-001. The detailed fire model tools are validated in CNS document R1906-711-01 and the analysis bases are provided.	Updates made to the Fire PRA in response to fire PRA peer review F&Os 3-1, 3-9, and 3-12, and 3-13 justify that the appropriate fire modeling tools are used within their limitations through a formal verification and validation process.	Disposition of this Peer Review Finding resulted in ensuring appropriate fire modeling verification and validation processes were performed. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
IGN-A5	Calculate generic fire ignition frequencies or plant-specific fire frequency updates on a reactor-year basis (generic fire frequencies are typically reported on this same basis). INCLUDE in the fire frequency calculation the plant availability, such that the frequencies are weighted by the fraction of time the plant is at-power.	Ignition frequencies are calculated on a reactor year basis in NEDC 08-032; however, they are not weighted by the fraction of time that the plant is at power. This can lead to an overestimate on the order of ten percent for the frequencies.	The Ignition Frequency Calculation NEDC 08-032 was updated to include the Average Criticality Factor from CNS-PSA-001, "Initiating Event Notebook." This value is used to convert the initiating event frequencies for this PSA update from critical to calendar years. This criticality factor is considered representative of the continual improvement in plant operation and appropriately represents future operation. Each of the Bin generic ignition frequencies identified in NEDC 08-032 has been updated to reflect plant-specific values weighted by the fraction of time that the plant is at power.	Disposition of this Peer Review Finding resulted in ensuring the average criticality factor was used. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
IGN-B1	Document all frequencies and event data used in the analysis in a manner that facilitates Fire PRA applications, upgrades, and peer review.	The total ignition frequencies are provided for the PAUs and for the fire zones in NEDC 08-032 Tables A-1 and A-2 of Appendix A. The frequencies for the specific ignition source bins in each PAU/fire zone used for other tasks are not provided in this document but they are contained in the ignition source data sheets. These frequencies should be documented in a report or calculation.	The Ignition Frequency Calculation NEDC 08-032 was updated to include the information directly from the Microsoft Excel spreadsheet used to perform the calculations to prevent typos in reproducing the data in the Microsoft Word document.	Disposition of this Peer Review Finding resulted in ensuring frequencies are in a calculation. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
HRA-D2	For any operator recovery actions identified in HRA-D1: a) account for relevant fire-related effects, including any effects that may preclude a recovery action or alter the manner in which it is accomplished, in accordance with HR-H2 and HR-H3 in Section 2; and b) develop a defined basis to support the claim of non-applicability of any of the requirements under HR-H2 and HR-H3 in Section 2.	Calculation NEDC 09-083 (Scientech Calculation 17712-003) "Post-Fire Human Reliability Analysis" addresses this issue. Recovery actions are only incorporated if they are existing EOP actions or if they are Fire Response actions. Existing EOP actions are identified in Table 4-1. Table 4-2 lists Fire Response HFEs Included In the FPRA. HFE mapping and treatment are documented in tables 4-3a/b/c/d, and table 4-4 through 4-9. Detailed HFE analysis is documented in Attachment B. Operator interviews are	Dependency Analysis was completed in NEDC 09-083, "Task 7.12 Human Reliability Analysis," and is summarized in NEDC 09-085 "Task 7.14 Fire Risk Quantification," as follows: Dependencies among operator actions exist for any of the following parameters that may have a common effect on operator actions including timing, procedures, cues, personnel, and staffing resources. Dependencies arise from post-initiator human error events that may be linked in the quantification process. If these operator actions are not independent, then any sequence cutsets associated with two or more of these dependent operator actions would be incorrect. The dependency analysis was performed in Task 7.12 using the EPRI HRA Calculator. The dependencies were identified and examined in the analysis by identifying	Disposition of this Peer Review Finding ensured that dependencies for human error events were identified and evaluated. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
		summarized in Section 6.4 and described in Attachment A. However, since HR-H3 is considered not met due to dependency analysis not being complete, this SR is considered not met.	combinations of operator actions and then determining their level of dependence.	
UNC-A1	Perform the uncertainty analysis in accordance with HLR-QU-E and its SRs in Section 2 as well as SRs LE-F2 and LE-F3 under HLR-LE-F in Section 2 and develop a defined basis to support the claim of non-applicability of any of the requirements under these sections in Section 2.	No quantitative estimated of parameter uncertainty was performed. See F&O 1-17. Qualitative evaluations of assumptions and uncertainty is provided in the uncertainty analysis NEDC 09-086 FPRA Uncertainty and Sensitivity r0.pdf.	See SR QU-E3	Disposition of this Peer Review Finding provided uncertainty interval estimates. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
QU-D7	Review the importance of components and basic events to determine that they make logical sense.	The FPRA does not include a development of a single cutset report or a list of importance measures for SSCs, Operator Actions or FPRA basic events.	Results were reviewed in detail and determined to make logical sense. This finding does not affect the results and use of the Fire PRA in the STI evaluation application. The calculation documentation was enhanced to clarify the definition of risk significance, and that all risk significant sequences at the fire damage state combined with CCDP and CLERP level are included in an attachment to the calculation. The CNS Fire PRA is extremely detailed in order to account for sequence dependent basic event values including spurious operations and human interaction.	Disposition of this Peer Review Finding ensured a review of cutsets for logical sense and validity. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
QU-F3	Document the significant contributors (such as initiating events, accident sequences, basic events) to CDF in the PRA results summary. Provide a detailed description of significant accident sequences or functional failure groups.	Significant initiating events and accident sequences have been documented in the fire quantification report Calculation 17712-011, Task 7.14 Fire Risk Quantification. A detailed description of significant accident sequences has been documented. However, due to the lack of single merged cutset files, significant basic events have not been documented.	Capability Category I is acceptable for this application as the actual results are not influenced by not achieving Capability Category II. The contributors at any level can be determined from a review of the cut-sets, including basic events. Importance ranking at the basis event level were not developed. The significant contributors at the sequence level are discussed.	No expected impact as addressed in the disposition for this F and O.
QU-F6	Document the quantitative definition used for significant basic event, significant cutset, and significant accident sequence. If it is other than the definition used in Part 2, justify the alternative.	The quantitative definition used for significant basic event, significant cutset, and significant accident sequence is not documented.	This finding does not affect the results and use of the Fire PRA in fire risk evaluations. NEDC 09-085, "Task 7.14 Fire Risk Quantification," was enhanced to clarify the definition of risk significance, and that all risk significant sequences at the fire damage state combined with CCDP and CLERP level are included in an attachment to the calculation. The CNS Fire PRA is extremely detailed in order to account for sequence dependent basic event values, including spurious operations and human interaction.	Disposition of this Peer Review Finding ensured risk significance was addressed. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
LE-G6	Document the quantitative definition used for significant accident progression sequence. If other than the definition used in Section 2, justify the alternative.	The quantitative definition used for significant basic event, significant cutset, and significant accident sequence is not documented.	This finding does not affect the results and use of the Fire PRA in fire risk evaluations. NEDC 09-085, "Task 7.14 Fire Risk Quantification," documentation was enhanced to clarify the definition of risk significance and that all risk significant sequences at the fire damage state combined with CCDP and CLERP level are included in an attachment to the calculation. The CNS Fire PRA is extremely detailed in order to account for sequence dependent basic event values including spurious operations and human interaction.	Disposition of this Peer Review Finding ensured risk significance was addressed. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
HR-E3	Talk through (i.e., review in detail) with plant operations and training personnel the procedures and sequence of events to confirm that interpretation of the procedures is consistent with plant observations and training procedures.	Operator interviews are documented in Attachment A of the HRA notebook. This includes talk-through of some of the FPRA actions, including walk-through on the simulator. However, a talk-through of all HEPs was not performed.	NEDC 09-083, "Task 7.12 Fire Human Reliability Analysis," was updated after further discussion of selected dominant scenarios and their associated operator actions. These actions were discussed in additional operator interviews. Also, a talk-through of actions was conducted.	Disposition of this Peer Review Finding ensured a talk through was performed for HEPs. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
HR-E4	Use simulator observations or talk-throughs with operators to confirm the response models for scenarios modeled.	Operator interviews are documented in Attachment A of the HRA notebook. This includes talk-through of some of the FPRA actions, including walk-through on the simulator. However, a talk-through of all HEPs was not performed.	NEDC 09-083, "Task 7.12 Fire Human Reliability Analysis," was updated after further discussion of selected dominant scenarios and their associated operator actions. These actions were discussed in additional operator interviews. Also, a talk-through of actions was conducted.	Disposition of this Peer Review Finding ensured risk significance was addressed. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
HR-G5	When needed, base the required time to complete actions for significant HFEs on action time measurements in either walkthroughs or talk-throughs of the procedures or simulator observations.	Operator action timing was based on walkthroughs, or talk-through, including simulator observations. Internal events PRA HEP actions used the internal events timing. For new actions, the actions were timed by the Appendix R feasibility analysis, as documented in Appendix M of the Appendix R analysis. However, not all HEPs were talked through with operations.	NEDC 09-083 "Task 7.12 Fire Human Reliability Analysis" was updated after further discussion of selected dominant scenarios and their associated operator actions. These actions were discussed in additional operator interviews. Also, a talk through of actions was conducted.	Disposition of this Peer Review Finding ensured risk significance was addressed. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
DA-D1	Calculate realistic parameter estimates for significant basic events based on relevant generic and plant specific evidence unless it is justified that there are adequate plant specific data to characterize the parameter value and its uncertainty. When it is necessary to combine evidence from generic and plant-specific	See PRM-B13.	With respect to new components added to support Fire PRA modeling, basic event/parameter grouping is from recognized industry sources such as NUREG/CR-6928, "Industry-average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants." The basic event Type Codes were established independent of the Fire PRA Model; therefore, no data reanalysis is necessary.	Disposition of this Peer Review Finding found that data used in the fire PRA has sound basis form industry sources of the CNS internal events PRA. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
	data, use a Bayes update process or equivalent statistical process that assigns appropriate weight to the statistical significance of the generic and plant-specific evidence and provides an appropriate characterization of uncertainty. 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.			
PP-B2	If partitioning credits wall, ceiling, or floor elements that lack a fire resistance rating, justify the judgment that the credited element will substantially contain the damaging effects of fires given the nature of the fire sources present in each compartment separated by the nonrated partitioning element.	The justification of partitioning between fire zone barriers to prevent full room burn-up not provided in some areas. These include 8H/8E, 8F/8E, 11A/11B, and 14A/14C.	Plant Boundary Definition and Partitioning Calculation NEDC 10-004 was updated to address fire compartments with multiple fire zones in which the fire zone boundaries may have been credited and whole room burnout approach taken to "screen" fire zones from detailed fire modeling. A review of the boundaries of the "screened" fire zones was performed via plant walkdown in order to confirm that these barriers are substantial enough to preclude fire spread to adjacent fire zones within the fire compartment. Detailed assessment of these barriers is provided in Multi-Compartment Analysis.	Disposition of this Peer Review Finding ensured that justification for partitioning was detailed and documented. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
FSS-C1	For each selected fire scenario, assign characteristics to the ignition source using a two-point fire intensity model that encompass low likelihood, but potentially risk contributing, fire events in the context of both fire intensity and duration given the nature of the fire ignition sources present.	An effective one point heat release rate model is used in the detailed fire modeling analyses (NEDC-091 - NEDC-101), except for MCR abandonment calculation (R1906-07-011b-001), which uses a fifteen point heat release rate model. The one point model approach typically identifies a threshold fire size and evaluates the time to damage given a 98th percentile growing fire.	The HRR distribution for each scenario has been discretized into two points in the Detailed Fire Modeling Calculations. The first point corresponds to the minimum HRR required to damage the nearest target, and its fire severity factor (SF) represents the fraction of fires that will damage only the ignition source itself. The second point corresponds to the 98th percentile HRR, and its SF represents the fraction of fires that will damage all targets within the Zone of Influence (ZOI) of the 98th percentile HRR, excluding the fraction of fires that will damage only the ignition source itself.	Disposition of this Peer Review Finding provided a two point approach. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
FSS-D3	For any physical analysis unit that represents a significant contributor to fire risk, select and apply fire modeling tools such that the scenario analysis provides reasonable assurance that the fire risk contribution of each unscreened physical analysis unit can be either bounded or realistically characterized.	EPM-DP-FP-001 Rev. 1 provides the methodology detailed fire modeling of potentially risk significant compartments. Compartment/zone detailed fire modeling are provided in calculations NEDC 09-091 through NEDC 09-101 and NEDC 10-001 Rev. 0. A review of the top cutsets indicates there are opportunities for improvement through the use of detailed fire modeling. For example, the 3B and 3A zone failure evaluations would benefit from creating fire scenarios which would save the bus duct for the emergency transformer and in the case of 3B the cross power cables.	Detailed fire modeling calculations have been developed for all fire zones deemed risk significant which include Fire Zones 3A (NEDC 10-046), 3B (NEDC 10-047), 8E (NEDC 10-043), 8F (NEDC 10-049), 8H (NEDC 10-043), 14A (NEDC 10-044), 14B (NEDC 10-045), and 13A (NEDC 09-095). These updates made to the Fire PRA in response to F&O 4-18 have incorporated detailed fire modeling scenario development for each of these unscreened risk significant areas and this SR is now considered to meet Cat II.	Disposition of this Peer Review Finding resulted in use of detail fire modeling where appropriate. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
FSS-E3	Provide a mean value of, and statistical representation of, the uncertainty intervals for the parameters used for modeling the significant fire scenarios.	The uncertainty parameters are characterized in Section 7.3 of the detailed fire modeling calculations NEDC 09-091 through NEDC 09-101. Mean values and distributions for these parameters are not established.	A consensus approach for meeting Capability Category II is not available. Prevailing good practice addresses this supporting requirement qualitatively, and thus is intended to meet Capability Category I. A reasonable "qualitative" characterization of the conditional probability of a FDS given a fire is a 90% range of -10 to +5 on the calculated point estimate. This approach is sufficient for fire risk evaluations. Where appropriate sensitivity evaluations are considered.	Disposition of this Peer Review Finding resulted in use of a approach sufficient for STI risk evaluations. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.
IGN-A10	Provide a mean value of, and a statistical representation of, the uncertainty intervals for significant fire ignition frequencies.	The characterization of uncertainty intervals is qualitatively discussed in the uncertainty analysis NEDC 09-086 FPRA Uncertainty and Sensitivity r0.pdf. A quantitative or statistical uncertainty estimate for each areas or scenario is not provided.	See SR QU-E3.	The resolution of the Peer Review finding validated adequacy of the uncertainty analysis and did not result in changes to the PRA model. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
CF-A1	Review the conditional failure probabilities for fire-induced circuit failures and assign the appropriate industry-wide generic values for risk-significant contributors based on the specific circuit configuration under consideration.	Initial quantification of circuit failures is set to a generic industry value of 0.3 or 0.6. When significant, specific circuit analysis is performed, this is documented in the Task 10 report. Table B of the Task 10 report is derived from the Task 9 report. Circuit failure likelihood is then developed in Table E-1 for each cable based on the generic SO probabilities, and the cable type, failure mode, etc. The specific circuit configuration for cables is included in the consideration. However, the plant specific analysis was not performed for all significant SO events. For example, in 3B, there are 5 events with FV> 0.01 that contain generic probabilities (0.6 or 0.3). In this area, all cables appear to be in conduit, which would likely result in a lower spurious operation probability for these events (unless SO is inside of an electrical cabinet). As a result, CC I is considered met, while CC II is considered not met.	The fire scenarios were further reviewed and additional detailed analysis was performed. This included not only detailed fire modeling and fire human reliability analysis, but also detailed circuit analysis and circuit failure likelihood analysis. Significant fire-induced failures of these scenarios were reviewed. The results of the detailed circuit analysis and circuit failure likelihood analysis are found in Task 9 (Calculation NEDC 09-073) and Task 10 (Calculation NEDC 09-082).	The resolution of the Peer Review finding provided additional detailed circuit analysis for significant fire induced failures. Hence, the finding has no impact on use of the CNS Internal Events PRA in the STI evaluation application.
HRA-A4	Talk through (i.e., review in detail) with plant operations and training personnel the procedures and sequence of events to confirm that interpretation of the procedures relevant to actions identified in SRs HRA-A1, HRA-A2, and HRA-A3 is consistent with plant operational and training practices.	Although there was a general over view of operational philosophy, there was not a talk-through of each new operator action.	NEDC 09-083, "Task 7.12 Fire Human Reliability Analysis," was updated after further discussion of selected dominant scenarios and their associated operator actions. These actions were discussed in additional operator interviews. Also, a talk-through of actions was conducted.	Disposition of this Peer Review Finding ensured a talk through was performed for HEPs. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
HRA-C1	For each selected fire scenario, quantify the HEPs for all HFEs and account for relevant fire-related effects using detailed analyses for significant HFEs and conservative estimates (e.g., screening values) for non-significant HFEs, in accordance with the SRs for HLR-HR-G in Section 2 set forth under at least Capability Category II, with the following clarification: a) Attention is to be given to how the fire situation alters any previous assessments in non-fire analyses as to the influencing factors and the timing considerations covered in SRs HR-G3, HR-G4, and HR-G5 in Section 2 and develop a defined basis to support the claim of non-applicability of any of the requirements under HLR-HRG in Part 2.	Detailed HRA was quantified in most cases for HEPs, accounting for fire-related effects. All SRs under HR-G were considered met other than the dependency SR HR-G6. Several F&Os were identified on these referenced SRs.	NEDC 09-083, "Task 7.12 Fire Human Reliability Analysis," documents the completed detailed HRA analysis for those HFEs in the FPRA as required. Consistency check of Fire PRA HFEs was completed and is documented in NEDC 09-083 "Task 7.12 Fire Human Reliability Analysis." This consistency check included such items as timing, use of appropriate HRA analysis method, scenario descriptions, procedures, and performance shaping factors. The fire scenarios were further reviewed and additional detailed analysis was performed if possible. This included not only detailed fire modeling and fire human reliability analysis, but also detailed circuit analysis and circuit failure likelihood analysis. A Dependency Analysis was completed in NEDC 09-083, "Task 7.12 Human Reliability Analysis," and is summarized in NEDC 09-085, "Task 7.14 Fire Risk Quantification," as follows: Dependencies among operator actions exist for any of the following parameters that may have a common effect on operator actions, including timing, procedures, cues, personnel, and staffing resources. Dependencies arise from post-initiator human error events that may be linked in the quantification process. If these operator actions are not independent, then any sequence cutsets associated with two or more of these dependent operator actions would be incorrect. The Dependency Analysis was performed in Task 7.12 using the EPRI HRA Calculator. The dependencies were identified and examined in the analysis by identifying combinations of operator actions and then determining their level of dependence. During the second interview with operators, effects of fires on travel paths were specifically reviewed and no significant change in travel time could be determined to occur. No further action is required. This is documented in NEDC 09-083, "Task 7.12 Fire Human Reliability Analysis."	Disposition of this Peer Review Finding ensured that dependencies for human error events were identified and evaluated. Hence the finding is expected to have no impact on use of the CNS Fire Events PRA in the STI evaluation application.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
QU-D6	Identify significant contributors to CDF, such as initiating events, accident sequences, equipment failures, common cause failures, and operator errors. Include SSCs and operator actions that contribute to initiating event frequencies and event mitigation.	Section 7.2 of the Quantification Analysis provides a discussion of all significant accident sequences in the FPRA. Discussion involves verification that the results are reasonable and accurate. Multi-compartment scenarios are reviewed in Section 7.3 and MCB scenarios are reviewed in Section 7.4. The FPRA model relies heavily on the internal events model logic, which was reviewed for consistency, including operational consistency. Operational consistency for fire includes the verification for scenarios that the equipment damaged is located in the compartment (cables or components). Additionally, review of HFEs is performed as part of the HRA for the FPRA. However, the FPRA does not include a development of a single cutset report or a list of importance measures for SSCs, Operator Actions or FPRA basic events. Additionally, the listing of the significant accident sequences does not list all significant accident sequences or significant SSCs as required by this SR (CC II).	Capability Category I is acceptable for this application as the actual results are not influenced by not achieving Capability Category II. The contributors at any level can be determined from a review of the cut-sets, including basic events. Importance ranking at the basis event level were not developed. The significant contributors at the sequence level are discussed.	No expected impact as addressed in the disposition for this F and O.

Table 2-2 Status of Identified Gaps to Capability Category II of the ASME PRA Standard for the CNS Fire PRA

SR	Category II Requirements	CNS Peer Review Facts and Observations Summary	CNS Disposition	Expected Impact on STI Evaluation Application
LE-G3	Document the relative contribution of contributors (i.e., plant damage states, accident progression sequences, phenomena, containment challenges, containment failure modes) to LERF.	CNS Calculation 17712-011, Task 7.14 Fire Risk Quantification, Section 7 and Attachment B document the significant contributors to LERF. However, the relative contribution of contributors (i.e., plant damage states, accident progression sequences, phenomena, containment challenges, containment failure modes) to LERF is not documented.	Capability Category I is acceptable for this application as the actual results are not influenced by not achieving Capability Category II, and STI evaluation can be supported. The contributors at any level can be determined from a review of the cut-sets, including basic events. The significant contributors at the sequence level are discussed in documentation.	No expected impact as addressed in the disposition for this F and O.

3.0 External Events Considerations

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.

External hazards were evaluated in 1996 in the CNS IPEEE submittal in response to the NRC IPEEE Program (Generic Letter 88-20, Supplement 4) [Reference 8]. The IPEEE Program was a one-time review of external hazard risk and was limited in its purpose to the identification of potential plant vulnerabilities and the understanding of associated severe accident risks.

The results of the CNS IPEEE study are documented in the CNS IPEEE Report [Reference 9]. The primary areas of external event evaluation at CNS were internal fire, seismic, high winds, floods, and other external hazards. Internal fire events were subsequently evaluated through development of a Fire PRA as detailed below.

Fire Analysis

Fire risk has been evaluated at CNS through use of a peer certified Fire PRA. This PRA will be used as directed by NEI 04-10, Revision 1, to assess aspects of fire risk when evaluating STI extensions. See section 2 above for discussion of the Fire PRA adequacy.

Seismic Analysis

The seismic portion of the IPEEE was completed in conjunction with the SQUG program [Reference 10]. CNS performed a seismic margin assessment (SMA) following the guidance of NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991 [Reference 11] and EPRI NP-6041-SL, Revision 1,"A Methodology for Assessment of Nuclear Power Plant Seismic Margin," August 1991 [Reference 12]. The SMA approach is a deterministic and conservative evaluation that does not calculate risk on a probabilistic basis. Therefore, its results cannot be compared directly with the best-estimate internal events results. The CNS seismic external event evaluations were reviewed as part of the submittal by the NRC and compared to the requirements of NUREG-1407 (Reference 11). The NRC transmitted to Nebraska Public Power District in 2001 their Staff Evaluation Report of the CNS IPEEE Submittal (Reference 14). The CNS IPEEE identified no significant seismic concerns, and it was concluded that the plant possesses significant seismic margin.

High Winds, Floods, and Other External Hazards (HFO)

In addition to internal fires and seismic events, the CNS IPEEE analysis of HFO external hazards was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards. Since CNS was designed (with construction started) prior to the issuance of the 1975 SRP criteria, CNS performed a plant hazard and design information review for conformance with the SRP criteria. For HFO events that were not screened out by compliance with the 1975 SRP criteria, additional analyses were

performed to determine whether or not the hazard frequency was acceptably low. The CNS HFO external event evaluations were reviewed as part of the submittal by the NRC and compared to the requirements of NUREG-1407 (Reference 11). The NRC transmitted to Nebraska Public Power District in 2001 their Staff Evaluation Report of the CNS IPEEE Submittal (Reference 14). Based on analyses, the CNS IPEEE did not find new significant vulnerabilities contributing to overall plant risk.

As stated earlier, the NEI 04-10 methodology allows for STI change evaluations to be performed in the absence of PRA models for fires, seismic, and HFOs as follows:

- For fire risk impacts, if the SSC is explicitly modeled and evaluated in the Fire PRA analyses, then the Fire PRA may be utilized to determine the acceptability of the STI change. If the SSC is determined to be implicitly modeled; then there is a choice of performing either a bounding analysis or a qualitative analysis. If the SSC is not modeled, (either explicitly or implicitly), the proposed STI change may still be justified if it is judged to have no impact on the PRA fire results. Where the SSC is qualitatively screened, the supporting information is summarized for presentation to the IDP.
- For seismic risk impacts, if the SSC is included in the SMA, then qualitative information may be developed that supports the acceptability of the STI change with respect to the seismic risk. If the SSC is not evaluated in the SMA, the proposed STI change may still be justified if it is judged that the SSC has no impact on the PRA seismic risk. In either case, the supporting information is summarized for presentation to the IDP.
- For HFOs, if the SSC is evaluated in the HFO external hazards analysis, then qualitative information may be developed that supports the acceptability of the STI change with respect to the external hazards risk. If the SSC is not evaluated in the external hazards screening evaluation, the proposed STI change may still be justified if it is judged that the SSC has no impact on the PRA external hazards risk. In either case, the supporting information is summarized for presentation to the IDP.

Therefore, in performing the assessments for the fire, seismic, and other external hazard groups, a Fire PRA, SMA evaluation, qualitative or a bounding approach will be utilized on case-by-case basis.

4.0 Summary

The CNS PRA technical capability evaluations and the maintenance and update processes described above provide a robust basis for concluding that the CNS PRA model and associated external event risk analysis results are suitable for use in the risk-informed process proposed for the implementation of a Surveillance Frequency Control Program. In addition to the standard set of sensitivity studies required per the NEI 04-10 methodology, any open MCR items related to changes at the site that may impact the PRA model but have not yet been incorporated or otherwise resolved, and any open F&Os not meeting Capability Category II from the Regulatory Guide 1.200 BWROG peer review will be reviewed to determine which, if any, would merit specific sensitivity studies to justify why the open items do not impact the PRA results used to support the STI change prior to presenting the results of the risk analysis to the IDP.

5.0 References

1) NEI 04-10, "Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies, Industry Guidance Document," Revision 1, April 2007

2) Regulatory Guide 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 1, January 2007

3) CNS-PSA-014, "Quantification Notebook," Revision 3

4) NEI 05-04, "Process for Performing Follow-on PRA Peer Reviews Using the ASME PRA Standard," Nuclear Energy Institute, Revision 1, Draft G, November 2007

5) ASME RA-Sc-2007 Addenda to, "ASME RA-S-2002 Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications," August 31, 2007

6) Cooper Nuclear Station PRA Peer Review Report Using ASME PRA Standard Requirements, June 2008

7) "Treatment of Parameter and Modeling Uncertainty for Probabilistic Risk Assessments," EPRI, Palo Alto, CA: December 2008 (Final) 1016737

8) NRC Generic Letter 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities - 10 CFR 50.54(f)," June 28, 1991

9) Cooper Nuclear Station, "Individual Plant Examination of External Events (IPEEE) Report - 10 CFR 50.54(f)," NLS960143, submitted October 1996

10) SQUG, "Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment," Revision 2, Corrected, February 14, 1992

11) NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991

12) Electric Power Research Institute, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin," EPRI NP-6041-SL, Revision 1, August 1991

13) NUREG-1855, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making," Volume 1, Main Report, March 2009

14) U.S. Nuclear Regulatory Commission, "Cooper Nuclear Station - Review of Individual Plant Examination of External Events (TAC No. 83611)," April 27, 2001

15) Scientech Calculation 17712-011, Task 7.14, "Fire Risk Quantification," NEDC 09-085, Revision 2

16) NEI 07-12, "Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines," Nuclear Energy Institute, Revision 0, Draft H, November 2008

17) 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," February 2, 2009

18) NRC Regulatory Guide 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 2, March 2009

19) "Cooper Nuclear Station Fire PRA Peer Review Report Using ASME PRA Standard Requirements," Revision 1, March 2011

Attachment 3

Proposed Technical Specification Changes
(Markup)

Cooper Nuclear Station, Docket No. 50-298, License No. DPR-46

Revised Technical Specification Pages

iv	3.3-55	3.6-13	3.8-8
1.1-5	3.3-56	3.6-14	3.8-9
3.1-10	3.3-59	3.6-15	3.8-15
3.1-13	3.3-62	3.6-16	3.8-17
3.1-17	3.3-65	3.6-17	3.8-18
3.1-19	3.3-68	3.6-19	3.8-23
3.1-21	3.4-3	3.6-21	3.8-24
3.1-22	3.4-5	3.6-22	3.8-27
3.1-26	3.4-7	3.6-24	3.8-30
3.2-1	3.4-9	3.6-26	3.9-2
3.2-2	3.4-11	3.6-29	3.9-3
3.2-4	3.4-13	3.6-30	3.9-4
3.3-3	3.4-16	3.6-32	3.9-7
3.3-4	3.4-18	3.6-33	3.9-8
3.3-5	3.4-20	3.6-35	3.9-11
3.3-11	3.4-22	3.6-39	3.9-14
3.3-12	3.4-26	3.6-42	3.10-5
3.3-16	3.5-3	3.7-2	3.10-8
3.3-17	3.5-4	3.7-4	3.10-12
3.3-18	3.5-5	3.7-5	3.10-14
3.3-21	3.5-6	3.7-7	3.10-15
3.3-24	3.5-9	3.7-10	3.10-17
3.3-26	3.5-10	3.7-12	3.10-22
3.3-27	3.5-12	3.7-13	3.10-23
3.3-30	3.5-13	3.7-15	5.0-18
3.3-36	3.6-2	3.8-5	
3.3-45	3.6-7	3.8-6	
3.3-50	3.6-12	3.8-7	

INSERT 1

In accordance with the Surveillance Frequency Control Program

INSERT 3

5.5.14 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 Operation 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 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

Amendment No.

1.1 Definitions

SHUTDOWN MARGIN (SDM) (continued)	b. The moderator temperature is 68°F; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.
~~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.
TURBINE BYPASS SYSTEM RESPONSE TIME	The TURBINE BYPASS SYSTEM RESPONSE TIME consists of two components: a. The time from initial movement of the main turbine stop valve or control valve until 80% of the turbine bypass capacity is established; and b. The time from initial movement of the main turbine stop valve or control valve until initial movement of the turbine bypass valve. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Determine the position of each control rod.	~~24 hours~~ INSERT 1
SR 3.1.3.2	(Deleted)	
SR 3.1.3.3	----------NOTE---------- Not required to be performed until 31 days after the control rod is withdrawn and THERMAL POWER is greater than the LPSP of the RWM. ---------- Insert each withdrawn control rod at least one notch.	~~31 days~~ INSERT 1
SR 3.1.3.4	Verify each control rod scram time from fully withdrawn to notch position 06 is ≤ 7 seconds.	In accordance with SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.4.2	Verify, for a representative sample, each tested control rod scram time is within the limits of Table 3.1.4-1 with reactor steam dome pressure ≥ 800 psig.	INSERT 1 ~~200 days cumulative operation in MODE 1~~
SR 3.1.4.3	Verify each affected control rod scram time is within the limits of Table 3.1.4-1 with any reactor steam dome pressure.	Prior to declaring control rod OPERABLE after work on control rod or CRD System that could affect scram time
SR 3.1.4.4	Verify each affected control rod scram time is within the limits of Table 3.1.4-1 with reactor steam dome pressure ≥ 800 psig.	Prior to exceeding 40% RTP after fuel movement within the affected core cell AND {add underline} Prior to exceeding 40% RTP after work on control rod or CRD System that could affect scram time

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more control rod scram accumulators inoperable with reactor steam dome pressure < 900 psig.	C.1 Verify the associated control rods are fully inserted.	Immediately upon discovery of charging water header pressure < 940 psig
	AND	
	C.2 Declare the associated control rod inoperable.	1 hour
D. Required Action B.1 or C.1 and associated Completion Time not met.	D.1 --------NOTE--------- Not applicable if all inoperable control rod scram accumulators are associated with fully inserted control rods. ----------	
	Place the reactor mode switch in the shutdown position.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each control rod scram accumulator pressure is ≥ 940 psig.	~~7 days~~ INSERT 1

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Nine or more OPERABLE control rods not in compliance with BPWS.	B.1 --------NOTE--------- Rod worth minimizer (RWM) may be bypassed as allowed by LCO 3.3.2.1. ---------- Suspend withdrawal of control rods.	Immediately
	AND	
	B.2 Place the reactor mode switch in the shutdown position.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify all OPERABLE control rods comply with BPWS.	~~24 hours~~ INSERT 1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify available volume of sodium pentaborate solution is within the limits of Figure 3.1.7-1.	~~24 hours~~ INSERT 1
SR 3.1.7.2	Verify temperature of sodium pentaborate solution is within the limits of Figure 3.1.7-2.	~~24 hours~~ INSERT 1
SR 3.1.7.3	Verify temperature of pump suction piping is within the limits of Figure 3.1.7-2.	~~24 hours~~ INSERT 1
SR 3.1.7.4	Verify continuity of explosive charge.	~~31 days~~ INSERT 1
SR 3.1.7.5	Verify the concentration of boron in solution is within the limits of Figure 3.1.7-1.	~~31 days~~ INSERT 1 AND Once within 24 hours after water or boron is added to solution AND Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-2

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.6	Verify each SLC subsystem manual valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	~~31 days~~ INSERT 1
SR 3.1.7.7	Verify each pump develops a flow rate ≥ 38.2 gpm at a discharge pressure ≥ 1300 psig.	In accordance with the Inservice Testing Program
SR 3.1.7.8	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	~~24 months on a STAGGERED TEST BASIS~~ INSERT 1
SR 3.1.7.9	Verify all heat traced piping between storage tank and pump suction is unblocked.	~~24 months~~ INSERT 1 AND Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	----------NOTE---------- Not required to be met on vent and drain valves closed during performance of SR 3.1.8.2. ---------- Verify each SDV vent and drain valve is open.	~~31 days~~ INSERT 1
SR 3.1.8.2	Cycle each SDV vent and drain valve to the fully closed and fully open position.	~~92 days~~ INSERT 1
SR 3.1.8.3	Verify each SDV vent and drain valve: a. Closes in ≤ 30 seconds after receipt of an actual or simulated scram signal; and b. Opens when the actual or simulated scram signal is reset.	~~24 months~~ INSERT 1

3.2 POWER DISTRIBUTION LIMITS

3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

LCO 3.2.1 All APLHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any APLHGR not within limits.	A.1 Restore APLHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify all APLHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 25% RTP AND ~~24 hours thereafter~~ INSERT 1

3.2 POWER DISTRIBUTION LIMITS

3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

LCO 3.2.2 All MCPRs shall be greater than or equal to the MCPR operating limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits.	A.1 Restore MCPR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 25% RTP AND ~~24 hours thereafter~~ INSERT 1

(continued)

3.2 POWER DISTRIBUTION LIMITS

3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

LCO 3.2.3 All LHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any LHGR not within limits.	A.1 Restore LHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify all LHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 25% RTP AND ~~24 hours thereafter~~ INSERT 1

SURVEILLANCE REQUIREMENTS

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

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

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	~~12 hours~~ INSERT 1
SR 3.3.1.1.2	----------NOTE---------- Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. ---------- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP plus any gain adjustment required by LCO 3.4.1, "Recirculation Loops Operating" while operating at ≥ 25% RTP.	~~7 days~~ INSERT 1
SR 3.3.1.1.3	----------NOTE---------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	~~7 days~~ INSERT 1
SR 3.3.1.1.4	Perform a functional test of each RPS channel test switch.	~~7 days~~ INSERT 1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.5	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to withdrawing SRMs from the fully inserted position
SR 3.3.1.1.6	----------NOTE---------- Only required to be met during entry into MODE 2 from MODE 1. ---------- Verify the IRM and APRM channels overlap.	~~7 days~~ INSERT 1
SR 3.3.1.1.7	Adjust the channel to conform to a calibrated flow signal.	~~31 days~~ INSERT 1
SR 3.3.1.1.8	Calibrate the local power range monitors.	~~1000 MWD/T average core exposure~~ INSERT 1
SR 3.3.1.1.9	Perform CHANNEL FUNCTIONAL TEST.	~~92 days~~ INSERT 1
SR 3.3.1.1.10	----------NOTES---------- 1. Neutron detectors and recirculation loop flow transmitters are excluded. 2. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	~~184 days~~ INSERT 1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.11	Perform CHANNEL FUNCTIONAL TEST.	~~24 months~~ INSERT 1
SR 3.3.1.1.12	----------NOTES---------- 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	~~24 months~~ INSERT 1
SR 3.3.1.1.13	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~24 months~~ INSERT 1
SR 3.3.1.1.14	Verify Turbine Stop Valve — Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure — Low Functions are not bypassed when THERMAL POWER is ≥ 29.5% RTP.	~~24 months~~ INSERT 1
SR 3.3.1.1.15	----------NOTE---------- Neutron detectors are excluded. ---------- Verify the RPS RESPONSE TIME is within limits.	~~24 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.1.2-1 to determine which SRs apply for each applicable MODE or other specified condition.

SURVEILLANCE		FREQUENCY
SR 3.3.1.2.1	Perform CHANNEL CHECK.	~~12 hours~~ INSERT 1
SR 3.3.1.2.2	----------NOTES---------- 1. Only required to be met during CORE ALTERATIONS. 2. One SRM may be used to satisfy more than one of the following. ---------- Verify an OPERABLE SRM detector is located in: a. The fueled region; b. The core quadrant where CORE ALTERATIONS are being performed, when the associated SRM is included in the fueled region; and c. A core quadrant adjacent to where CORE ALTERATIONS are being performed, when the associated SRM is included in the fueled region.	~~12 hours~~ INSERT 1
SR 3.3.1.2.3	Perform CHANNEL CHECK.	~~24 hours~~ INSERT 1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.2.4	----------NOTE---------- Not required to be met with less than or equal to four fuel assemblies adjacent to the SRM and no other fuel assemblies in the associated core quadrant. ---------- Verify count rate is ≥ 3.0 cps with a signal to noise ratio ≥ 2:1.	INSERT 1 ~~12 hours during CORE ALTERATIONS~~ ~~AND~~ ~~24 hours~~
SR 3.3.1.2.5	Perform CHANNEL FUNCTIONAL TEST and determination of signal to noise ratio.	INSERT 1 ~~7 days~~
SR 3.3.1.2.6	----------NOTE---------- Not required to be performed until 12 hours after IRMs on Range 2 or below. ---------- Perform CHANNEL FUNCTIONAL TEST and determination of signal to noise ratio.	INSERT 1 ~~31 days~~
SR 3.3.1.2.7	----------NOTES---------- 1. Neutron detectors are excluded. 2. Not required to be performed until 12 hours after IRMs on Range 2 or below. ---------- Perform CHANNEL CALIBRATION.	INSERT 1 ~~24 months~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One or more Reactor Mode Switch — Shutdown Position channels inoperable.	E.1 Suspend control rod withdrawal.	Immediately
	AND	
	E.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.2.1-1 to determine which SRs apply for each Control Rod Block Function.

2. When an RBM channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains control rod block capability.

SURVEILLANCE	FREQUENCY
SR 3.3.2.1.1 Perform CHANNEL FUNCTIONAL TEST.	INSERT 1 ~~92 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.2	----------NOTE---------- Not required to be performed until 1 hour after any control rod is withdrawn at ≤ 9.85% RTP in MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	INSERT 1 ~~92 days~~
SR 3.3.2.1.3	----------NOTE---------- Not required to be performed until 1 hour after THERMAL POWER is ≤ 9.85% RTP in MODE 1. ---------- Perform CHANNEL FUNCTIONAL TEST.	INSERT 1 ~~92 days~~
SR 3.3.2.1.4	----------NOTE---------- Neutron detectors are excluded. ---------- Verify the RBM: a. Low Power Range — Upscale Function is not bypassed when THERMAL POWER is ≥ 27.5% and < 62.5% RTP and a peripheral control rod is not selected. b. Intermediate Power Range — Upscale Function is not bypassed when THERMAL POWER is ≥ 62.5% and < 82.5% RTP and a peripheral control rod is not selected. c. High Power Range — Upscale Function is not bypassed when THERMAL POWER is ≥ 82.5% RTP and a peripheral control rod is not selected.	INSERT 1 ~~184 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.5	----------NOTE---------- Neutron detectors are excluded. ---------- Perform CHANNEL CALIBRATION.	~~184 days~~ INSERT 1
SR 3.3.2.1.6	Verify the RWM is not bypassed when THERMAL POWER is ≤ 9.85% RTP.	~~24 months~~ INSERT 1
SR 3.3.2.1.7	----------NOTE---------- Not required to be performed until 1 hour after reactor mode switch is in the shutdown position. ---------- Perform CHANNEL FUNCTIONAL TEST.	~~24 months~~ INSERT 1
SR 3.3.2.1.8	Verify control rod sequences input to the RWM are in conformance with BPWS.	Prior to declaring RWM OPERABLE following loading of sequence into RWM

SURVEILLANCE REQUIREMENTS

----------NOTE----------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided feedwater and main turbine high water level trip capability is maintained.

SURVEILLANCE		FREQUENCY
SR 3.3.2.2.1	Perform CHANNEL CHECK.	~~24 hours~~ INSERT 1
SR 3.3.2.2.2	Perform CHANNEL CALIBRATION. The Allowable Value shall be ≤ 54.0 inches.	~~24 months~~ INSERT 1
SR 3.3.2.2.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including valve actuation.	~~24 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.3.1.1	Perform CHANNEL CHECK on each required PAM Instrumentation channel.	~~31 days~~ INSERT 1
SR 3.3.3.1.2	Perform CHANNEL CALIBRATION of the Primary Containment H_2 and O_2 Analyzers.	~~92 days~~ INSERT 1
SR 3.3.3.1.3	Perform CHANNEL CALIBRATION of each required PAM Instrumentation channel except for the Primary Containment H_2 and O_2 Analyzers.	~~24 months~~ INSERT 1

3.3 INSTRUMENTATION

3.3.3.2 Alternate Shutdown System

LCO 3.3.3.2 The Alternate Shutdown System Functions shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

NOTE
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required Functions inoperable.	A.1 Restore required Function to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.3.2.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	~~31 days~~ INSERT 1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.3.2.2	Verify each required control circuit and transfer switch is capable of performing the intended function.	~~24 months~~ INSERT 1
SR 3.3.3.2.3	Perform CHANNEL CALIBRATION for each required instrumentation channel.	~~24 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

----------NOTE----------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains ATWS-RPT trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.1	Perform CHANNEL FUNCTIONAL TEST.	~~92 days~~ INSERT 1
SR 3.3.4.1.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Reactor Vessel Water Level — Low Low (Level 2): ≥ -42 inches; and b. Reactor Pressure — High: ≤ 1072 psig.	~~24 months~~ INSERT 1
SR 3.3.4.1.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	~~24 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

NOTES

1. Refer to Table 3.3.5.1-1 to determine which SRs apply for each ECCS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 3.c and 3.f; and (b) for up to 6 hours for Functions other than 3.c and 3.f provided the associated Function or the redundant Function maintains ECCS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.1	Perform CHANNEL CHECK.	~~12 hours~~ INSERT 1
SR 3.3.5.1.2	Perform CHANNEL FUNCTIONAL TEST.	~~92 days~~ INSERT 1
SR 3.3.5.1.3	Perform CHANNEL CALIBRATION.	~~92 days~~ INSERT 1
SR 3.3.5.1.4	Perform CHANNEL CALIBRATION.	~~24 months~~ INSERT 1
SR 3.3.5.1.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~24 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.5.2-1 to determine which SRs apply for each RCIC Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Function 2; and (b) for up to 6 hours for Functions 1 and 3 provided the associated Function maintains RCIC initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.2.1	Perform CHANNEL CHECK.	~~12 hours~~ INSERT 1
SR 3.3.5.2.2	Perform CHANNEL FUNCTIONAL TEST.	~~92 days~~ INSERT 1
SR 3.3.5.2.3	Perform CHANNEL CALIBRATION.	~~92 days~~ INSERT 1
SR 3.3.5.2.4	Perform CHANNEL CALIBRATION.	~~24 months~~ INSERT 1
SR 3.3.5.2.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~24 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

NOTES

1. Refer to Table 3.3.6.1-1 to determine which SRs apply for each Primary Containment Isolation Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains isolation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.1	Perform CHANNEL CHECK.	~~12 hours~~ INSERT 1
SR 3.3.6.1.2	Perform CHANNEL FUNCTIONAL TEST.	~~92 days~~ INSERT 1
SR 3.3.6.1.3	Perform CHANNEL CALIBRATION.	~~92 days~~ INSERT 1
SR 3.3.6.1.4	NOTE For Function 2.d, radiation detectors are excluded. Perform CHANNEL CALIBRATION.	~~24 months~~ INSERT 1
SR 3.3.6.1.5	Calibrate each radiation detector.	~~24 months~~ INSERT 1
SR 3.3.6.1.6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~24 months~~ INSERT 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.1.2 Declare associated secondary containment isolation valves inoperable.	1 hour
	AND	
	C.2.1 Place the associated standby gas treatment (SGT) subsystem(s) in operation.	1 hour
	OR	
	C.2.2 Declare associated SGT subsystem(s) inoperable.	1 hour

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.6.2-1 to determine which SRs apply for each Secondary Containment Isolation Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains secondary containment isolation capability.

SURVEILLANCE	FREQUENCY
SR 3.3.6.2.1 Perform CHANNEL CHECK.	~~12 hours~~ INSERT 1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.2.2	Perform CHANNEL FUNCTIONAL TEST.	INSERT 1 ~~92 days~~
SR 3.3.6.2.3	Perform CHANNEL CALIBRATION.	INSERT 1 ~~24 months~~
SR 3.3.6.2.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	INSERT 1 ~~24 months~~

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.6.3-1 to determine which SRs apply for each Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains LLS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.3.1	Perform CHANNEL FUNCTIONAL TEST for portion of the channel outside primary containment.	~~92 days~~ INSERT 1
SR 3.3.6.3.2	----------NOTE---------- Only required to be performed prior to entering MODE 2 during each scheduled outage > 72 hours when entry is made into primary containment. ---------- Perform CHANNEL FUNCTIONAL TEST for portions of the channel inside primary containment.	~~92 days~~ INSERT 1
SR 3.3.6.3.3	Perform CHANNEL FUNCTIONAL TEST.	~~92 days~~ INSERT 1
SR 3.3.6.3.4	Perform CHANNEL CALIBRATION.	~~24 months~~ INSERT 1
SR 3.3.6.3.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~24 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

NOTES

1. Refer to Table 3.3.7.1-1 to determine which SRs apply for each CREF Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains CREF initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.7.1.1	Perform CHANNEL CHECK.	~~12 hours~~ INSERT 1
SR 3.3.7.1.2	Perform CHANNEL FUNCTIONAL TEST.	~~92 days~~ INSERT 1
SR 3.3.7.1.3	Perform CHANNEL CALIBRATION.	~~24 months~~ INSERT 1
SR 3.3.7.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~24 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

NOTES

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains DG initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL FUNCTIONAL TEST.	~~31 days~~ INSERT 1
SR 3.3.8.1.2	Perform CHANNEL CALIBRATION.	~~24 months~~ INSERT 1
SR 3.3.8.1.3	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~24 months~~ INSERT 1

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A or B not met in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	D.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.1	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Overvoltage ≤ 131 V with time delay set to ≤ 3.8 seconds. b. Undervoltage ≥ 109 V, with time delay set to ≤ 3.8 seconds. c. Underfrequency ≥ 57.2 Hz, with time delay set to ≤ 3.8 seconds.	INSERT 1 ~~24 months~~
SR 3.3.8.2.2	Perform a system functional test.	INSERT 1 ~~24 months~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	----------NOTE---------- Not required to be performed until 24 hours after both recirculation loops are in operation. ---------- Verify recirculation loop flow mismatch with both recirculation loops in operation is: a. ≤ 10% of rated core flow when operating at < 70% of rated core flow; and b. ≤ 5% of rated core flow when operating at ≥ 70% of rated core flow.	INSERT 1 ~~24 hours~~
SR 3.4.1.2	Verify core flow as a function of THERMAL POWER is not in the Stability Exclusion Region of the power/flow map specified in the COLR.	INSERT 1 ~~24 hours~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	----------NOTES---------- 1. Not required to be performed until 4 hours after associated recirculation loop is in operation. 2. Not required to be performed until 24 hours after > 25% RTP. ---------- Verify at least one of the following criteria (a or b) is satisfied for each operating recirculation loop: a. Recirculation pump flow to speed ratio differs by ≤ 5% from established patterns, and jet pump loop flow to recirculation pump speed ratio differs by ≤ 5% from established patterns. b. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns.	INSERT 1 ~~24 hours~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	Verify the safety function lift setpoints of the SRVs and SVs are as follows: Number of SRVs — Setpoint (psig) 2 — 1080 ± 32.4 3 — 1090 ± 32.7 3 — 1100 ± 33.0 Number of SVs — Setpoint (psig) 3 — 1240 ± 37.2 Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program
SR 3.4.3.2	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify each SRV opens when manually actuated.	~~24 months~~ INSERT 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Verify source of unidentified LEAKAGE increase is not service sensitive type 304 or type 316 austenitic stainless steel.	4 hours
C. Required Action and associated Completion Time of Condition A or B not met. OR Pressure boundary LEAKAGE exists.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.4.1	Verify RCS unidentified and total LEAKAGE and unidentified LEAKAGE increase are within limits.	~~12 hours~~ INSERT 1

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. All required leakage detection systems inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Perform a CHANNEL CHECK of required drywell atmospheric monitoring channel.	~~12 hours~~ INSERT 1
SR 3.4.5.2	Perform a CHANNEL FUNCTIONAL TEST of required leakage detection instrumentation.	~~31 days~~ INSERT 1
SR 3.4.5.3	Perform a CHANNEL CALIBRATION of required leakage detection instrumentation.	~~92 days~~ INSERT 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2.2.1 Be in MODE 3.	12 hours
	AND	
	B.2.2.2 Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	----------NOTE---------- Only required to be performed in MODE 1. ---------- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity is ≤ 0.2 μCi/gm.	INSERT 1 ~~7 days~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	----------NOTE---------- Not required to be met until 2 hours after reactor steam dome pressure is less than the shutdown cooling permissive pressure. ---------- Verify one RHR shutdown cooling subsystem or recirculation pump is operating.	INSERT 1 ~~12 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. No RHR shutdown cooling subsystem in operation. AND No recirculation pump in operation.	B.1 Verify reactor coolant circulating by an alternate method.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter
	AND	
	B.2 Monitor reactor coolant temperature.	Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify one RHR shutdown cooling subsystem or recirculation pump is operating.	~~12 hours~~ INSERT 1

ACTIONS (continued)

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	----------NOTE---------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. ----------	
	Verify:	INSERT 1 ~~30 minutes~~
	a. RCS pressure and RCS temperature are within the applicable limits specified in Figures 3.4.9-1 and 3.4.9-2; and	
	b. RCS heatup and cooldown rates are ≤ 100°F when averaged over a one hour period.	

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.9.5	----------NOTE---------- Only required to be performed when tensioning the reactor vessel head bolting studs. ---------- Verify reactor vessel flange and head flange temperatures are > 70°F.	INSERT 1 ~~30 minutes~~
SR 3.4.9.6	----------NOTE---------- Not required to be performed until 30 minutes after RCS temperature ≤ 80°F in MODE 4. ---------- Verify reactor vessel flange and head flange temperatures are > 70°F.	INSERT 1 ~~30 minutes~~
SR 3.4.9.7	----------NOTE---------- Not required to be performed until 12 hours after RCS temperature ≤ 90°F in MODE 4. ---------- Verify reactor vessel flange and head flange temperatures are > 70°F.	INSERT 1 ~~12 hours~~

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Reactor Steam Dome Pressure

LCO 3.4.10 The reactor steam dome pressure shall be ≤ 1020 psig.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor steam dome pressure not within limit.	A.1 Restore reactor steam dome pressure to within limit.	15 minutes
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.10.1 Verify reactor steam dome pressure is ≤ 1020 psig.	INSERT 1 ~~12 hours~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Required Action and associated Completion Time of Condition C, D, E, or F not met. OR Two or more ADS valves inoperable.	G.1 Be in MODE 3. AND G.2 Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours
H. Two or more low pressure ECCS injection/spray subsystems inoperable for reasons other than condition A. OR HPCI System and one or more ADS valves inoperable.	H.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify, for each ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	INSERT 1 ~~31 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.2	----------NOTE---------- Low pressure coolant injection (LPCI) subsystems may be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the shutdown cooling permissive pressure in MODE 3, if capable of being manually realigned and not otherwise inoperable. ---------- Verify each ECCS injection/spray subsystem 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.	INSERT 1 ~~31 days~~
SR 3.5.1.3	Verify ADS pneumatic supply header pressure is ≥ 88 psig.	INSERT 1 ~~31 days~~
SR 3.5.1.4	Verify the RHR System cross tie shutoff valve is closed.	INSERT 1 ~~31 days~~
SR 3.5.1.5	----------NOTE---------- Not required to be performed if performed within the previous 31 days. ---------- Verify each recirculation pump discharge valve cycles through one complete cycle of full travel or is de-energized in the closed position.	Once each startup prior to exceeding 25% RTP

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.6	Verify the following ECCS pumps develop the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF Core Spray: ≥ 4720 gpm, 1, ≥ 113 psig LPCI: ≥ 15,000 gpm, 2, ≥ 20 psig	In accordance with the Inservice Testing Program
SR 3.5.1.7	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify, with reactor pressure ≤ 1020 and ≥ 920 psig, the HPCI pump can develop a flow rate ≥ 4250 gpm against a system head corresponding to reactor pressure.	~~92 days~~ INSERT 1
SR 3.5.1.8	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify, with reactor pressure ≤ 165 psig, the HPCI pump can develop a flow rate ≥ 4250 gpm against a system head corresponding to reactor pressure.	~~24 months~~ INSERT 1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.9	----------NOTES---------- 1 For HPCI only, not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. 2. Vessel injection/spray may be excluded. ---------- Verify each ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	~~24 months~~ INSERT 1
SR 3.5.1.10	----------NOTE---------- Valve actuation may be excluded ---------- Verify the ADS actuates on an actual or simulated automatic initiation signal.	~~24 months~~ INSERT 1
SR 3.5.1.11	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify each ADS valve opens when manually actuated.	~~24 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify, for each required ECCS injection/spray subsystem, the suppression pool water level is ≥ 12 ft 7 inches.	~~12 hours~~ INSERT 1
SR 3.5.2.2	Verify, for each required ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	~~31 days~~ INSERT 1
SR 3.5.2.3	----------NOTE---------- One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable. ---------- Verify each required ECCS injection/spray subsystem 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~~ INSERT 1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.4	Verify each required ECCS pump develops the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM — FLOW RATE — NO. OF PUMPS — SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF CS — ≥ 4720 gpm — 1 — ≥ 113 psig LPCI — ≥ 7700 gpm — 1 — ≥ 20 psig	In accordance with the Inservice Testing Program
SR 3.5.2.5	----------NOTE---------- Vessel injection/spray may be excluded. ---------- Verify each required ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	~~24 months~~ INSERT 1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	Verify the RCIC System piping is filled with water from the pump discharge valve to the injection valve.	~~31 days~~ INSERT 1
SR 3.5.3.2	Verify each RCIC System 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~~ INSERT 1
SR 3.5.3.3	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify, with reactor pressure ≤ 1020 psig and ≥ 920 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.	~~92 days~~ INSERT 1
SR 3.5.3.4	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify, with reactor pressure ≤ 165 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.	~~24 months~~ INSERT 1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.3.5	----------NOTES---------- 1. Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. 2. Vessel injection may be excluded. ---------- Verify the RCIC System actuates on an actual or simulated automatic initiation signal.	INSERT 1 ~~24 months~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1.1	Perform required visual examinations and leakage rate testing except for primary containment air lock testing, in accordance with the Primary Containment Leakage Rate Testing Program.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.1.2	Verify drywell to suppression chamber bypass leakage is equivalent to a hole < 1.0 inch in diameter.	INSERT 1 ~~24 months~~ AND -------NOTE------- Only required after two consecutive tests fail and continues until two consecutive tests pass ---------- 9 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.1	----------NOTES---------- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1.1. ---------- Perform required primary containment air lock leakage rate testing in accordance with the Primary Containment Leakage Rate Testing Program.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.2.2	Verify only one door in the primary containment air lock can be opened at a time.	INSERT 1 ~~24 months~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.1	----------NOTES---------- 1. Not required to be met when the 24 inch primary containment purge and vent valves are open in one supply line and one exhaust line for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. 2. When the purging or venting in accordance with Note 1 is through the Standby Gas Treatment (SGT) System, both SGT subsystems shall be OPERABLE, and only one SGT subsystem shall be operating. ---------- Verify each 24 inch primary containment purge and vent valve is closed.	INSERT 1 ~~31 days~~
SR 3.6.1.3.2	----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for PCIVs that are open under administrative controls. ---------- Verify each primary containment isolation manual valve and blind flange that is located outside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	INSERT 1 ~~31 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.3	----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for PCIVs that are open under administrative controls. ---------- Verify each primary containment manual isolation valve and blind flange that is located inside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	Prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days
SR 3.6.1.3.4	Verify continuity of the traversing incore probe (TIP) shear isolation valve explosive charge.	INSERT 1 ~~31 days~~
SR 3.6.1.3.5	Verify the isolation time of each power operated, automatic PCIV, except for MSIVs, is within limits.	In accordance with the Inservice Testing Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.6	Verify the isolation time of each MSIV is ≥ 3 seconds and ≤ 5 seconds.	In accordance with the Inservice Testing Program
SR 3.6.1.3.7	Verify each automatic PCIV actuates to the isolation position on an actual or simulated isolation signal.	~~24 months~~ INSERT 1
SR 3.6.1.3.8	Verify a representative sample of reactor instrumentation line EFCVs actuate to the isolation position on an actual or simulated instrument line break.	~~24 months~~ INSERT 1
SR 3.6.1.3.9	Remove and test the explosive squib from each shear isolation valve of the TIP System.	~~24 months on a STAGGERED TEST BASIS~~ INSERT 1
SR 3.6.1.3.10	Verify leakage rate through each Main Steam line is ≤ 106 scfh when tested at ≥ 29 psig.	In accordance with the Primary Containment Leakage Rate Testing Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.11	Verify each inboard 24 inch primary containment purge and vent valve is blocked to restrict the maximum valve opening angle to 60°.	INSERT 1 ~~24 months~~
SR 3.6.1.3.12	Verify leakage rate through the Main Steam Pathway is ≤ 212 scfh when tested at ≥ 29 psig.	In accordance with the Primary Containment Leakage Rate Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.1.4 Drywell Pressure

LCO 3.6.1.4 Drywell pressure shall be ≤ 0.75 psig.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Drywell pressure not within limit.	A.1 Restore drywell pressure to within limit.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.1.4.1 Verify drywell pressure is within limit.	INSERT 1 ~~12 hours~~

3.6 CONTAINMENT SYSTEMS

3.6.1.5 Drywell Air Temperature

LCO 3.6.1.5 Drywell average air temperature shall be ≤ 150°F.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Drywell average air temperature not within limit.	A.1 Restore drywell average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.1.5.1 Verify drywell average air temperature is within limit.	INSERT 1 ~~24 hours~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.1	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify each LLS valve opens when manually actuated.	INSERT 1 ~~24 months~~
SR 3.6.1.6.2	----------NOTE---------- Valve actuation may be excluded. ---------- Verify the LLS System actuates on an actual or simulated automatic initiation signal.	INSERT 1 ~~24 months~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two lines with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening.	D.1 Restore all vacuum breakers in one line to OPERABLE status.	1 hour
E. Required Action and Associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.7.1	----------NOTES---------- 1. Not required to be met for vacuum breakers that are open during Surveillances. 2. Not required to be met for vacuum breakers open when performing their intended function. ---------- Verify each vacuum breaker is closed.	INSERT 1 ~~14 days~~
SR 3.6.1.7.2	Perform a functional test of each vacuum breaker.	INSERT 1 ~~92 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.7.3	Verify the full open setpoint of each vacuum breaker is ≤ 0.5 psid.	INSERT 1 ~~24 months~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.8.1	----------NOTE---------- Not required to be met for vacuum breakers that are open during Surveillances. ---------- Verify each vacuum breaker is closed.	INSERT 1 ~~14 days~~
SR 3.6.1.8.2	Perform a functional test of each required vacuum breaker.	INSERT 1 ~~31 days~~
SR 3.6.1.8.3	Verify the opening setpoint of each required vacuum breaker is ≤ 0.5 psid.	INSERT 1 ~~24 months~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.9.1	Verify each RHR containment spray subsystem 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 or can be aligned to the correct position.	INSERT 1 ~~31 days~~
SR 3.6.1.9.2	Verify each required RHR pump develops a flow rate of > 7700 gpm through the associated heat exchanger while operating in the suppression pool cooling mode.	In accordance with the Inservice Testing Program
SR 3.6.1.9.3	Verify each spray nozzle is unobstructed.	Following maintenance which could result in nozzle blockage

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Suppression pool average temperature > 120°F.	E.1	Depressurize the reactor vessel to < 200 psig.	12 hours
	AND		
	E.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1.1	Verify suppression pool average temperature is within the applicable limits.	INSERT 1 ~~24 hours~~ AND 5 minutes when performing testing that adds heat to the suppression pool

3.6 CONTAINMENT SYSTEMS

3.6.2.2 Suppression Pool Water Level

LCO 3.6.2.2 Suppression pool water level shall be ≥ 12 ft 7 inches and ≤ 12 ft 11 inches.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Suppression pool water level not within limits.	A.1	Restore suppression pool water level to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	AND		
	B.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.2.1	Verify suppression pool water level is within limits.	~~24 hours~~ INSERT 1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.3.1	Verify each RHR suppression pool cooling subsystem 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 or can be aligned to the correct position.	~~31 days~~ INSERT 1
SR 3.6.2.3.2	Verify each RHR pump develops a flow rate > 7700 gpm through the associated heat exchanger while operating in the suppression pool cooling mode.	In accordance with the Inservice Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.3.1 Primary Containment Oxygen Concentration

LCO 3.6.3.1 The primary containment oxygen concentration shall be < 4.0 volume percent.

APPLICABILITY: MODE 1 during the time period:

a. From 24 hours after THERMAL POWER is > 15% RTP following startup, to

b. 24 hours prior to reducing THERMAL POWER to < 15% RTP prior to a reactor shutdown.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Primary containment oxygen concentration not within limit.	A.1	Restore oxygen concentration to within limit.	24 hours
B. Required Action and associated Completion Time not met.	B.1	Reduce THERMAL POWER to ≤ 15% RTP.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1.1	Verify primary containment oxygen concentration is within limits.	~~7 days~~ INSERT 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Initiate action to suspend OPDRVs.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.1	Verify secondary containment vacuum is ≥ 0.25 inch of vacuum water gauge.	~~24 hours~~ INSERT 1
SR 3.6.4.1.2	Verify all secondary containment equipment hatches are closed and sealed.	~~31 days~~ INSERT 1
SR 3.6.4.1.3	Verify one secondary containment access door in each access opening is closed.	~~31 days~~ INSERT 1
SR 3.6.4.1.4	Verify each SGT subsystem can maintain ≥ 0.25 inch of vacuum water gauge in the secondary containment for 1 hour at a flow rate ≤ 1780 cfm.	~~24 months on a STAGGERED TEST BASIS~~ INSERT 1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.2.1	----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for SCIVs that are open under administrative controls. ---------- Verify each secondary containment isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	~~31 days~~ INSERT 1
SR 3.6.4.2.2	Verify the isolation time of each power operated automatic SCIV is within limits.	In accordance with the Inservice Testing Program
SR 3.6.4.2.3	Verify each automatic SCIV actuates to the isolation position on an actual or simulated actuation signal.	~~24 months~~ INSERT 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. (continued)	E.2 Initiate action to suspend OPDRVs.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.3.1	Operate each SGT subsystem for ≥ 10 continuous hours with heaters operating.	~~31 days~~ INSERT 1
SR 3.6.4.3.2	Perform required SGT filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.6.4.3.3	Verify each SGT subsystem actuates on an actual or simulated initiation signal.	~~24 months~~ INSERT 1
SR 3.6.4.3.4	Verify the SGT units cross tie damper is in the correct position, and each SGT room air supply check valve and SGT dilution air shutoff valve can be opened.	~~24 months~~ INSERT 1

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met. OR Both RHRSWB subsystems inoperable.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify each RHRSWB manual and power operated valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	~~31 days~~ INSERT 1

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. OR Both SW subsystems inoperable. OR UHS inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	Verify the river water level is ≥ 865 ft mean sea level.	INSERT 1 ~~24 hours~~
SR 3.7.2.2	Verify the average water temperature of UHS is ≤ 95°F.	INSERT 1 ~~24 hours~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.2.3	----------NOTE---------- Isolation of flow to individual components does not render SW System inoperable. ---------- Verify each SW subsystem manual, power operated, and automatic valve in the flow paths servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position.	INSERT 1 ~~31 days~~
SR 3.7.2.4	Verify each SW subsystem actuates on an actual or simulated initiation signal.	INSERT 1 ~~24 months~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	----------NOTES---------- 1. SR 3.0.1 is not applicable when both Service Water backup subsystems are OPERABLE. 2. REC system leakage beyond limits by itself is only a degradation of the REC system and does not result in the REC system being inoperable. ---------- Verify the REC system leakage is within limits.	INSERT 1 ~~24 hours~~
SR 3.7.3.2	Verify the temperature of the REC supply water is ≤ 100°F.	INSERT 1 ~~24 hours~~
SR 3.7.3.3	----------NOTE---------- Isolation of flow to individual components does not render REC System inoperable. ---------- Verify each REC subsystem manual, power operated, and automatic valve in the flow paths servicing safety related cooling loads, that is not locked, sealed, or otherwise secured in position, is in the correct position.	INSERT 1 ~~31 days~~
SR 3.7.3.4	Verify each REC subsystem actuates on an actual or simulated initiation signal.	INSERT 1 ~~24 months~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Operate the CREF System for ≥ 15 minutes.	INSERT 1 ~~31 days~~
SR 3.7.4.2	Perform required CREF filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP.
SR 3.7.4.3	Verify the CREF System actuates on an actual or simulated initiation signal.	INSERT 1 ~~24 months.~~
SR 3.7.4.4	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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	----------NOTE---------- Not required to be performed until 31 days after any main steam line not isolated and SJAE in operation. ---------- Verify the gross gamma activity rate of the noble gases is ≤ 1.0 Ci/second.	INSERT 1 ~~31 days~~ AND Once within 4 hours after a ≥ 50% increase in the nominal steady state fission gas release after factoring out increases due to changes in THERMAL POWER level.

3.7 PLANT SYSTEMS

3.7.6 Spent Fuel Storage Pool Water Level

LCO 3.7.6 The spent fuel storage pool water level shall be ≥ 21 ft 6 inches over the top of irradiated fuel assemblies seated in the spent fuel storage pool racks.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spent 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 spent fuel storage pool.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify the spent fuel storage pool water level is ≥ 21 ft 6 inches over the top of irradiated fuel assemblies seated in the spent fuel storage pool racks.	INSERT 1 ~~7 days~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	Verify operation of each main turbine bypass valve.	INSERT 1 ~~31 days~~
SR 3.7.7.2	Perform a system functional test.	INSERT 1 ~~24 months~~
SR 3.7.7.3	Verify the TURBINE BYPASS SYSTEM RESPONSE TIME is within limits.	INSERT 1 ~~24 months~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	~~7 days~~ INSERT 1
SR 3.8.1.2	----------NOTES---------- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. ---------- Verify each DG starts from standby conditions and achieves steady state voltage ≥ 3950 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	~~31 days~~ INSERT 1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	----------NOTES---------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow, without shutdown, a successful performance of SR 3.8.1.2 or SR 3.8.1.7. ---------- Verify each DG is synchronized and loaded and operates for ≥ 2 hours at a load ≥ 3600 kW and ≤ 4000 kW.	INSERT 1 ~~31 days~~
SR 3.8.1.4	Verify each day tank contains ≥ 1500 gal of fuel oil.	INSERT 1 ~~31 days~~
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	INSERT 1 ~~31 days~~
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tanks to the day tanks.	INSERT 1 ~~92 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.7	----------NOTE---------- All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts from standby condition and achieves, in ≤ 14 seconds, voltage ≥ 3950 V and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 3950 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	INSERT 1 ~~184 days~~
SR 3.8.1.8	----------NOTE---------- This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify automatic and manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit.	INSERT 1 ~~24 months~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. 3. If performed with DG synchronized with offsite power, the surveillance shall be performed at a power factor ≤ 0.89. 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 DG operates for ≥ 8 hours: a. For ≥ 2 hours loaded ≥ 4200 kW and ≤ 4400 kW; and b. For the remaining hours of the test loaded ≥ 3600 kW and ≤ 4000 kW.	INSERT 1 ~~24 months~~
SR 3.8.1.10	----------NOTES---------- This Surveillance shall not be performed in MODE 1, 2 or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify interval between each sequenced load is within ± 10% of nominal timer setpoint.	INSERT 1 ~~24 months~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 14 seconds, 2. energizes auto-connected emergency loads through the timed logic sequence, 3. maintains steady state voltage ≥ 3950 V and ≤ 4400 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	INSERT 1 ~~24 months~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify the fuel oil storage tanks contain a combined volume of ≥ 49,500 gal of fuel.	INSERT 1 ~~31 days~~
SR 3.8.3.2	Verify lube oil inventory is ≥ 504 gal.	INSERT 1 ~~31 days~~
SR 3.8.3.3	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 3.8.3.4	Verify each DG has a minimum of one air start receiver with a pressure ≥ 200 psig.	INSERT 1 ~~31 days~~
SR 3.8.3.5	Check for and remove accumulated water from each fuel oil storage tank.	INSERT 1 ~~31 days~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage on float charge is: a. ≥ 125.9 V for the 125 V batteries; and b. ≥ 260.4 V for the 250 V batteries.	INSERT 1 ~~7 days~~
SR 3.8.4.2	Verify no visible corrosion at battery terminals and connectors. OR Verify battery connection resistance meets the limits specified in Table 3.8.4-1.	INSERT 1 ~~92 days~~
SR 3.8.4 3	Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration that degrades battery performance.	INSERT 1 ~~18 months~~
SR 3.8.4.4	Remove visible corrosion and verify battery cell to cell and terminal connections are coated with anti-corrosion material.	INSERT 1 ~~18 months~~
SR 3.8.4.5	Verify battery connection resistance meets the limits specified in Table 3.8.4-1.	INSERT 1 ~~18 months~~
SR 3.8.4.6	Verify: a Each required 125 V battery charger supplies ≥ 200 amps at ≥ 125 V for ≥ 4 hours; and b Each required 250 V battery charger supplies ≥ 200 amps at ≥ 250 V for ≥ 4 hours.	INSERT 1 ~~24 months~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.7	----------NOTES---------- 1 The modified performance discharge test in SR 3.8.4.8 may be performed in lieu of the service test in SR 3.8.4.7 ~~once per 60 months~~. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- 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.	INSERT 1 ~~24 months~~
SR 3.8.4.8	----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify battery capacity is ≥ 90% of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	INSERT 1 ~~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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Restore battery cell parameters to Category A and B limits of Table 3.8.6-1.	31 days
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 not within limits. OR One or more batteries with one or more battery cell parameters not within Category C limits.	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.	INSERT 1 ~~7 days~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.6.2	Verify battery cell parameters meet Table 3.8.6-1 Category B limits.	INSERT 1 ~~92 days~~ AND Once within 24 hours after battery discharge < 105 V for a 125 V battery or < 210 V for a 250 V battery AND Once within 24 hours after battery overcharge > 140 V for a 125 V battery or > 280 V for a 250 V battery
SR 3.8.6.3	Verify average electrolyte temperature of representative cells is ≥ 70°F.	INSERT 1 ~~92 days~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. One or more 250 V DC electrical power distribution subsystems inoperable.	D.1 Declare associated supported feature(s) inoperable.	Immediately
E. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct breaker alignments and voltage to required AC and DC, electrical power distribution subsystems.	~~7 days~~ INSERT 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.4 Initiate actions to restore required AC and DC electrical power distribution subsystems to OPERABLE status.	Immediately
	AND	
	A.2.5 Declare associated required shutdown cooling subsystem(s) inoperable and not in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct breaker alignments and voltage to required AC and DC electrical power distribution subsystems.	INSERT 1 ~~7 days~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Perform CHANNEL FUNCTIONAL TEST on each of the following required refueling equipment interlock inputs: a. All-rods-in, b. Refuel platform position, c. Refuel platform fuel grapple, fuel loaded, d. Refuel platform fuel grapple not full up, e. Refuel platform frame mounted hoist, fuel loaded, f. Refuel platform monorail mounted hoist, fuel loaded, and g. Service platform hoist, fuel loaded.	INSERT 1 ~~7 days~~

3.9 REFUELING OPERATIONS

3.9.2 Refuel Position One-Rod-Out Interlock

LCO 3.9.2 The refuel position one-rod-out interlock shall be OPERABLE.

APPLICABILITY: MODE 5 with the reactor mode switch in the refuel position and any control rod withdrawn.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refuel position one-rod-out interlock inoperable.	A.1 Suspend control rod withdrawal.	Immediately
	AND	
	A.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Verify reactor mode switch locked in refuel position.	INSERT 1 ~~12 hours~~
SR 3.9.2.2	----------NOTE---------- Not required to be performed until 1 hour after any control rod is withdrawn. ---------- Perform CHANNEL FUNCTIONAL TEST.	INSERT 1 ~~7 days~~

3.9 REFUELING OPERATIONS

3.9.3 Control Rod Position

LCO 3.9.3 All control rods shall be fully inserted.

APPLICABILITY: When loading fuel assemblies into the core.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more control rods not fully inserted.	A.1 Suspend loading fuel assemblies into the core.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.9.3.1 Verify all control rods are fully inserted.	INSERT 1 ~~12 hours~~

3.9 REFUELING OPERATIONS

3.9.5 Control Rod OPERABILITY—Refueling

LCO 3.9.5 Each withdrawn control rod shall be OPERABLE.

APPLICABILITY: MODE 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more withdrawn control rods inoperable.	A.1 Initiate action to fully insert inoperable withdrawn control rods.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	----------NOTE---------- Not required to be performed until 7 days after the control rod is withdrawn. ---------- Insert each withdrawn control rod at least one notch.	INSERT 1 ~~7 days~~
SR 3.9.5.2	Verify each withdrawn control rod scram accumulator pressure is ≥ 940 psig.	INSERT 1 ~~7 days~~

3.9 REFUELING OPERATIONS

3.9.6 Reactor Pressure Vessel (RPV) Water Level

LCO 3.9.6 RPV water level shall be ≥ 21 ft above the top of the RPV flange.

APPLICABILITY: During movement of irradiated fuel assemblies within the RPV,
During movement of new fuel assemblies or handling of control rods within the RPV, when irradiated fuel assemblies are seated within the RPV.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RPV water level not within limit.	A.1 Suspend movement of fuel assemblies and handling of control rods within the RPV.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify RPV water level is ≥ 21 ft above the top of the RPV flange.	~~24 hours~~ INSERT 1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.7.1	Verify one RHR shutdown cooling subsystem is operating.	INSERT 1 ~~12 hours~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.8.1	Verify one RHR shutdown cooling subsystem is operating.	INSERT 1 ~~12 hours~~

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3.1 Place the reactor mode switch in the shutdown position.	1 hour
	OR	
	A.3.2 --------NOTE--------- Only applicable in MODE 5. ---------- Place the reactor mode switch in the refuel position.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.2.1	Verify all control rods are fully inserted in core cells containing one or more fuel assemblies.	INSERT 1 ~~12 hours~~
SR 3.10.2.2	Verify no CORE ALTERATIONS are in progress.	INSERT 1 ~~24 hours~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.3.1	Perform the applicable SRs for the required LCOs.	According to the applicable SRs
SR 3.10.3.2	----------NOTE---------- Not required to be met if SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements. ---------- Verify all control rods, other than the control rod being withdrawn, in a five by five array centered on the control rod being withdrawn, are disarmed.	INSERT 1 ~~24 hours~~
SR 3.10.3.3	Verify all control rods, other than the control rod being withdrawn, are fully inserted.	INSERT 1 ~~24 hours~~

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.10.4.2	----------NOTE---------- Not required to be met if SR 3.10.4.1 is satisfied for LCO 3.10.4.c.1 requirements. ---------- Verify all control rods, other than the control rod being withdrawn, in a five by five array centered on the control rod being withdrawn, are disarmed.	INSERT 1 ~~24 hours~~
SR 3.10.4.3	Verify all control rods, other than the control rod being withdrawn, are fully inserted.	INSERT 1 ~~24 hours~~
SR 3.10.4.4	----------NOTE---------- Not required to be met if SR 3.10.4.1 is satisfied for LCO 3.10.4.b.1 requirements. ---------- Verify a control rod withdrawal block is inserted.	INSERT 1 ~~24 hours~~

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.1 Initiate action to fully insert all control rods.	Immediately
	OR	
	A.2.2 Initiate action to satisfy the requirements of this LCO.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.5.1	Verify all control rods, other than the control rod withdrawn for the removal of the associated CRD, are fully inserted.	~~24 hours~~ INSERT 1
SR 3.10.5.2	Verify all control rods, other than the control rod withdrawn for the removal of the associated CRD, in a five by five array centered on the control rod withdrawn for the removal of the associated CRD, are disarmed.	~~24 hours~~ INSERT 1
SR 3.10.5.3	Verify a control rod withdrawal block is inserted.	~~24 hours~~ INSERT 1
SR 3.10.5.4	Perform SR 3.1.1.1.	According to SR 3.1.1.1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.10.5.5	Verify no other CORE ALTERATIONS are in progress.	INSERT 1 ~~24 hours~~

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3.1 Initiate action to fully insert all control rods in core cells containing one or more fuel assemblies.	Immediately
	OR	
	A.3.2 Initiate action to satisfy the requirements of this LCO.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.6.1	Verify the four fuel assemblies are removed from core cells associated with each control rod or CRD removed.	INSERT 1 ~~24 hours~~
SR 3.10.6.2	Verify all other control rods in core cells containing one or more fuel assemblies are fully inserted.	INSERT 1 ~~24 hours~~
SR 3.10.6.3	----------NOTE---------- Only required to be met during fuel loading. ---------- Verify fuel assemblies being loaded are in compliance with an approved spiral reload sequence.	INSERT 1 ~~24 hours~~

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.10.8.2	----------NOTE---------- Not required to be met if SR 3.10.8.3 satisfied. ---------- Perform the MODE 2 applicable SRs for LCO 3.3.2.1, Function 2 of Table 3.3.2.1-1.	According to the applicable SRs
SR 3.10.8.3	----------NOTE---------- Not required to be met if SR 3.10.8.2 satisfied. ---------- Verify movement of control rods is in compliance with the approved control rod sequence for the SDM test by a second licensed operator or other qualified member of the technical staff.	During control rod movement
SR 3.10.8.4	Verify no other CORE ALTERATIONS are in progress.	INSERT 1 ~~12 hours~~
SR 3.10.8.5	Verify each withdrawn control rod does not go to the withdrawn overtravel position.	Each time the control rod is withdrawn to "full out" position AND Prior to satisfying LCO 3.10.8.c requirement after work on control rod or CRD System that could affect coupling

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.10.8.6	Verify CRD charging water header pressure ≥ 940 psig.	~~7 days~~ INSERT 1

5.5 Programs and Manuals

5.5.13 Control Room Envelope Habitability Program (continued)

personnel receiving radiation exposures in excess of either (a) 5 rem whole body or its equivalent to any part of the body for the duration of the loss-of-coolant accident, or (b) 5 rem total effective dose equivalent (TEDE) for the duration of the fuel handling accident. The program shall include the following elements:

a. The definition of the CRE and CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0. No exceptions to Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0, are proposed.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by the CREF System, operating at the flow rate required by the Ventilation Filter Testing Program, at a Frequency of 24 months. The results shall be trended and used as part of the periodic assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered air inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

INSERT 3

Attachment 4
Proposed Technical Specification Pages
(Re-Typed)

Cooper Nuclear Station, Docket No. 50-298, License No. DPR-46

Revised Technical Specification Pages

iv	3.3-55	3.6-13	3.8-8
1.1-5	3.3-56	3.6-14	3.8-9
3.1-10	3.3-59	3.6-15	3.8-15
3.1-13	3.3-62	3.6-16	3.8-17
3.1-17	3.3-65	3.6-17	3.8-18
3.1-19	3.3-68	3.6-19	3.8-23
3.1-21	3.4-3	3.6-21	3.8-24
3.1-22	3.4-5	3.6-22	3.8-27
3.1-26	3.4-7	3.6-24	3.8-30
3.2-1	3.4-9	3.6-26	3.9-2
3.2-2	3.4-11	3.6-29	3.9-3
3.2-4	3.4-13	3.6-30	3.9-4
3.3-3	3.4-16	3.6-32	3.9-7
3.3-4	3.4-18	3.6-33	3.9-8
3.3-5	3.4-20	3.6-35	3.9-11
3.3-11	3.4-22	3.6-39	3.9-14
3.3-12	3.4-26	3.6-42	3.10-5
3.3-16	3.5-3	3.7-2	3.10-8
3.3-17	3.5-4	3.7-4	3.10-12
3.3-18	3.5-5	3.7-5	3.10-14
3.3-21	3.5-6	3.7-7	3.10-15
3.3-24	3.5-9	3.7-10	3.10-17
3.3-26	3.5-10	3.7-12	3.10-22
3.3-27	3.5-12	3.7-13	3.10-23
3.3-30	3.5-13	3.7-15	5.0-18
3.3-36	3.6-2	3.8-5	5.0-19 (new)
3.3-45	3.6-7	3.8-6	
3.3-50	3.6-12	3.8-7	

The following pages are included due to repagination: 5.0-20, 5.0-21, 5.0-22, and 5.0-23

1.1 Definitions

SHUTDOWN MARGIN (SDM) (continued)	b. The moderator temperature is 68°F; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.
TURBINE BYPASS SYSTEM RESPONSE TIME	The TURBINE BYPASS SYSTEM RESPONSE TIME consists of two components: a. The time from initial movement of the main turbine stop valve or control valve until 80% of the turbine bypass capacity is established; and b. The time from initial movement of the main turbine stop valve or control valve until initial movement of the turbine bypass valve. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Determine the position of each control rod.	In accordance with the Surveillance Frequency Control Program
SR 3.1.3.2	(Deleted)	
SR 3.1.3.3	----------NOTE---------- Not required to be performed until 31 days after the control rod is withdrawn and THERMAL POWER is greater than the LPSP of the RWM. ----------	
	Insert each withdrawn control rod at least one notch.	In accordance with the Surveillance Frequency Control Program
SR 3.1.3.4	Verify each control rod scram time from fully withdrawn to notch position 06 is ≤ 7 seconds.	In accordance with SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.4.2	Verify, for a representative sample, each tested control rod scram time is within the limits of Table 3.1.4-1 with reactor steam dome pressure ≥ 800 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.1.4.3	Verify each affected control rod scram time is within the limits of Table 3.1.4-1 with any reactor steam dome pressure.	Prior to declaring control rod OPERABLE after work on control rod or CRD System that could affect scram time
SR 3.1.4.4	Verify each affected control rod scram time is within the limits of Table 3.1.4-1 with reactor steam dome pressure ≥ 800 psig.	Prior to exceeding 40% RTP after fuel movement within the affected core cell AND Prior to exceeding 40% RTP after work on control rod or CRD System that could affect scram time

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more control rod scram accumulators inoperable with reactor steam dome pressure < 900 psig.	C.1	Verify the associated control rods are fully inserted.	Immediately upon discovery of charging water header pressure < 940 psig
	AND		
	C.2	Declare the associated control rod inoperable.	1 hour
D. Required Action B.1 or C.1 and associated Completion Time not met.	D.1	----------NOTE---------- Not applicable if all inoperable control rod scram accumulators are associated with fully inserted control rods. ----------	
		Place the reactor mode switch in the shutdown position.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each control rod scram accumulator pressure is ≥ 940 psig.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Nine or more OPERABLE control rods not in compliance with BPWS.	B.1	----------NOTE---------- Rod worth minimizer (RWM) may be bypassed as allowed by LCO 3.3.2.1. ----------	
		Suspend withdrawal of control rods.	Immediately
	AND		
	B.2	Place the reactor mode switch in the shutdown position.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify all OPERABLE control rods comply with BPWS.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify available volume of sodium pentaborate solution is within the limits of Figure 3.1.7-1.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.2	Verify temperature of sodium pentaborate solution is within the limits of Figure 3.1.7-2.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.3	Verify temperature of pump suction piping is within the limits of Figure 3.1.7-2.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.4	Verify continuity of explosive charge.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.5	Verify the concentration of boron in solution is within the limits of Figure 3.1.7-1.	In accordance with the Surveillance Frequency Control Program AND Once within 24 hours after water or boron is added to solution AND (continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
(continued)		Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-2
SR 3.1.7.6	Verify each SLC subsystem manual valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.7	Verify each pump develops a flow rate ≥ 38.2 gpm at a discharge pressure ≥ 1300 psig.	In accordance with the Inservice Testing Program
SR 3.1.7.8	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	In accordance with the Surveillance Frequency Control Program
SR 3.1.7.9	Verify all heat traced piping between storage tank and pump suction is unblocked.	In accordance with the Surveillance Frequency Control Program AND Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	----------NOTE---------- Not required to be met on vent and drain valves closed during performance of SR 3.1.8.2. ---------- Verify each SDV vent and drain valve is open.	In accordance with the Surveillance Frequency Control Program
SR 3.1.8.2	Cycle each SDV vent and drain valve to the fully closed and fully open position.	In accordance with the Surveillance Frequency Control Program
SR 3.1.8.3	Verify each SDV vent and drain valve: a. Closes in ≤ 30 seconds after receipt of an actual or simulated scram signal; and b. Opens when the actual or simulated scram signal is reset.	In accordance with the Surveillance Frequency Control Program

3.2 POWER DISTRIBUTION LIMITS

3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

LCO 3.2.1 All APLHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any APLHGR not within limits.	A.1 Restore APLHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify all APLHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 25% RTP AND In accordance with the Surveillance Frequency Control Program

3.2 POWER DISTRIBUTION LIMITS

3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

LCO 3.2.2 All MCPRs shall be greater than or equal to the MCPR operating limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits.	A.1 Restore MCPR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 25% RTP AND In accordance with the Surveillance Frequency Control Program

(continued)

3.2 POWER DISTRIBUTION LIMITS

3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

LCO 3.2.3 All LHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any LHGR not within limits.	A.1 Restore LHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify all LHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 25% RTP AND In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

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

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

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.2	----------NOTE---------- Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. ----------	
	Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP plus any gain adjustment required by LCO 3.4.1, "Recirculation Loops Operating" while operating at ≥ 25% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.3	----------NOTE---------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ----------	
	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.4	Perform a functional test of each RPS channel test switch.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.5	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to withdrawing SRMs from the fully inserted position
SR 3.3.1.1.6	----------NOTE---------- Only required to be met during entry into MODE 2 from MODE 1. ---------- Verify the IRM and APRM channels overlap.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.7	Adjust the channel to conform to a calibrated flow signal.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.8	Calibrate the local power range monitors.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.9	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.10	----------NOTES---------- 1. Neutron detectors and recirculation loop flow transmitters are excluded. 2. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.11	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.12	----------NOTES---------- 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ----------	
	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.13	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.14	Verify Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 29.5% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.15	----------NOTE---------- Neutron detectors are excluded. ----------	
	Verify the RPS RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

----------NOTE----------

Refer to Table 3.3.1.2-1 to determine which SRs apply for each applicable MODE or other specified condition.

SURVEILLANCE		FREQUENCY
SR 3.3.1.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2.2	----------NOTES---------- 1. Only required to be met during CORE ALTERATIONS. 2. One SRM may be used to satisfy more than one of the following. ---------- Verify an OPERABLE SRM detector is located in: a. The fueled region; b. The core quadrant where CORE ALTERATIONS are being performed, when the associated SRM is included in the fueled region; and c. A core quadrant adjacent to where CORE ALTERATIONS are being performed, when the associated SRM is included in the fueled region.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2.3	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.2.4	----------NOTE---------- Not required to be met with less than or equal to four fuel assemblies adjacent to the SRM and no other fuel assemblies in the associated core quadrant. ---------- Verify count rate is ≥ 3.0 cps with a signal to noise ratio ≥ 2:1.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2.5	Perform CHANNEL FUNCTIONAL TEST and determination of signal to noise ratio.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2.6	----------NOTE---------- Not required to be performed until 12 hours after IRMs on Range 2 or below. ---------- Perform CHANNEL FUNCTIONAL TEST and determination of signal to noise ratio.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2.7	----------NOTES---------- 1. Neutron detectors are excluded. 2. Not required to be performed until 12 hours after IRMs on Range 2 or below. ---------- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One or more Reactor Mode Switch - Shutdown Position channels inoperable.	E.1 Suspend control rod withdrawal. AND E.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.2.1-1 to determine which SRs apply for each Control Rod Block Function.

2. When an RBM channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains control rod block capability.

SURVEILLANCE	FREQUENCY
SR 3.3.2.1.1 Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.2	----------NOTE---------- Not required to be performed until 1 hour after any control rod is withdrawn at ≤ 9.85% RTP in MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.3	----------NOTE---------- Not required to be performed until 1 hour after THERMAL POWER is ≤ 9.85% RTP in MODE 1. ---------- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.4	----------NOTE---------- Neutron detectors are excluded. ---------- Verify the RBM: a. Low Power Range - Upscale Function is not bypassed when THERMAL POWER is ≥ 27.5% and < 62.5% RTP and a peripheral control rod is not selected. b. Intermediate Power Range - Upscale Function is not bypassed when THERMAL POWER is ≥ 62.5% and < 82.5% RTP and a peripheral control rod is not selected. c. High Power Range - Upscale Function is not bypassed when THERMAL POWER is ≥ 82.5% RTP and a peripheral control rod is not selected.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.5	----------NOTE---------- Neutron detectors are excluded. ---------- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.6	Verify the RWM is not bypassed when THERMAL POWER is ≤ 9.85% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.7	----------NOTE---------- Not required to be performed until 1 hour after reactor mode switch is in the shutdown position. ---------- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.8	Verify control rod sequences input to the RWM are in conformance with BPWS.	Prior to declaring RWM OPERABLE following loading of sequence into RWM

SURVEILLANCE REQUIREMENTS

----------NOTE----------

When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided feedwater and main turbine high water level trip capability is maintained.

SURVEILLANCE		FREQUENCY
SR 3.3.2.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.2.2	Perform CHANNEL CALIBRATION. The Allowable Value shall be ≤ 54.0 inches.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.2.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including valve actuation.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.3.1.1	Perform CHANNEL CHECK on each required PAM Instrumentation channel.	In accordance with the Surveillance Frequency Control Program
SR 3.3.3.1.2	Perform CHANNEL CALIBRATION of the Primary Containment H_2 and O_2 Analyzers.	In accordance with the Surveillance Frequency Control Program
SR 3.3.3.1.3	Perform CHANNEL CALIBRATION of each required PAM Instrumentation channel except for the Primary Containment H_2 and O_2 Analyzers.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.3.2 Alternate Shutdown System

LCO 3.3.3.2 The Alternate Shutdown System Functions shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required Functions inoperable.	A.1	Restore required Function to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.3.2.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.3.2.2	Verify each required control circuit and transfer switch is capable of performing the intended function.	In accordance with the Surveillance Frequency Control Program
SR 3.3.3.2.3	Perform CHANNEL CALIBRATION for each required instrumentation channel.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

----------NOTE----------

When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains ATWS-RPT trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.1	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Reactor Vessel Water Level - Low Low (Level 2): ≥ -42 inches; and b. Reactor Pressure - High: ≤ 1072 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.5.1-1 to determine which SRs apply for each ECCS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Functions 3.c and 3.f; and (b) for up to 6 hours for Functions other than 3.c and 3.f provided the associated Function or the redundant Function maintains ECCS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.5.2-1 to determine which SRs apply for each RCIC Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Function 2; and (b) for up to 6 hours for Functions 1 and 3 provided the associated Function maintains RCIC initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.2.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.2.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.2.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.2.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.6.1-1 to determine which SRs apply for each Primary Containment Isolation Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains isolation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.4	----------NOTE---------- For Function 2.d, radiation detectors are excluded. ---------- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.5	Calibrate each radiation detector.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.1.2 Declare associated secondary containment isolation valves inoperable.	1 hour
	AND	
	C.2.1 Place the associated standby gas treatment (SGT) subsystem(s) in operation.	1 hour
	OR	
	C.2.2 Declare associated SGT subsystem(s) inoperable.	1 hour

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.6.2-1 to determine which SRs apply for each Secondary Containment Isolation Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains secondary containment isolation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMTNS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.2.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.2.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.2.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.6.3-1 to determine which SRs apply for each Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains LLS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.3.1	Perform CHANNEL FUNCTIONAL TEST for portion of the channel outside primary containment.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.3.2	----------NOTE---------- Only required to be performed prior to entering MODE 2 during each scheduled outage > 72 hours when entry is made into primary containment. ----------	
	Perform CHANNEL FUNCTIONAL TEST for portions of the channel inside primary containment.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.3.3	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.3.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.3.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.7.1-1 to determine which SRs apply for each CREF Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains CREF initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.7.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.7.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.7.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.7.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains DG initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.2	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.3	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A or B not met in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies.	D.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.2.1	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Overvoltage ≤ 131 V with time delay set to ≤ 3.8 seconds. b. Undervoltage ≥ 109 V, with time delay set to ≤ 3.8 seconds. c. Underfrequency ≥ 57.2 Hz, with time delay set to ≤ 3.8 seconds.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.2.2	Perform a system functional test.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	----------NOTE---------- Not required to be performed until 24 hours after both recirculation loops are in operation. ---------- Verify recirculation loop flow mismatch with both recirculation loops in operation is: a. ≤ 10% of rated core flow when operating at < 70% of rated core flow; and b. ≤ 5% of rated core flow when operating at ≥ 70% of rated core flow.	In accordance with the Surveillance Frequency Control Program
SR 3.4.1.2	Verify core flow as a function of THERMAL POWER is not in the Stability Exclusion Region of the power/flow map specified in the COLR.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	----------NOTES---------- 1. Not required to be performed until 4 hours after associated recirculation loop is in operation. 2. Not required to be performed until 24 hours after > 25% RTP. ----------	
	Verify at least one of the following criteria (a or b) is satisfied for each operating recirculation loop: a. Recirculation pump flow to speed ratio differs by ≤ 5% from established patterns, and jet pump loop flow to recirculation pump speed ratio differs by ≤ 5% from established patterns. b. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	Verify the safety function lift setpoints of the SRVs and SVs are as follows: Number of SRVs — Setpoint (psig) 2 — 1080 ± 32.4 3 — 1090 ± 32.7 3 — 1100 ± 33.0 Number of SVs — Setpoint (psig) 3 — 1240 ± 37.2 Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program
SR 3.4.3.2	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify each SRV opens when manually actuated.	In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Verify source of unidentified LEAKAGE increase is not service sensitive type 304 or type 316 austenitic stainless steel.	4 hours
C. Required Action and associated Completion Time of Condition A or B not met. OR Pressure boundary LEAKAGE exists.	C.1 AND C.2	Be in MODE 3. Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.4.1	Verify RCS unidentified and total LEAKAGE and unidentified LEAKAGE increase are within limits.	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.	C.1	Be in MODE 3.	12 hours
	AND		
	C.2	Be in MODE 4.	36 hours
D. All required leakage detection systems inoperable.	D.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Perform a CHANNEL CHECK of required drywell atmospheric monitoring channel.	In accordance with the Surveillance Frequency Control Program
SR 3.4.5.2	Perform a CHANNEL FUNCTIONAL TEST of required leakage detection instrumentation.	In accordance with the Surveillance Frequency Control Program
SR 3.4.5.3	Perform a CHANNEL CALIBRATION of required leakage detection instrumentation.	In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2.2.1 Be in MODE 3.	12 hours
	AND	
	B.2.2.2 Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	----------NOTE---------- Only required to be performed in MODE 1. ---------- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity is ≤ 0.2 μCi/gm.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	----------NOTE---------- Not required to be met until 2 hours after reactor steam dome pressure is less than the shutdown cooling permissive pressure. ----------	
	Verify one RHR shutdown cooling subsystem or recirculation pump is operating.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. No RHR shutdown cooling subsystem in operation. AND No recirculation pump in operation.	B.1	Verify reactor coolant circulating by an alternate method.	1 hour from discovery of no reactor coolant circulation AND Once per 12 hours thereafter
	AND		
	B.2	Monitor reactor coolant temperature.	Once per hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify one RHR shutdown cooling subsystem or recirculation pump is operating.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	----------NOTE---------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. ----------	
	Verify: a. RCS pressure and RCS temperature are within the applicable limits specified in Figures 3.4.9-1 and 3.4.9-2; and b. RCS heatup and cooldown rates are ≤ 100°F when averaged over a one hour period.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.9.5	----------NOTE---------- Only required to be performed when tensioning the reactor vessel head bolting studs. ---------- Verify reactor vessel flange and head flange temperatures are > 70°F.	In accordance with the Surveillance Frequency Control Program
SR 3.4.9.6	----------NOTE---------- Not required to be performed until 30 minutes after RCS temperature ≤ 80°F in MODE 4. ---------- Verify reactor vessel flange and head flange temperatures are > 70°F.	In accordance with the Surveillance Frequency Control Program
SR 3.4.9.7	----------NOTE---------- Not required to be performed until 12 hours after RCS temperature ≤ 90°F in MODE 4. ---------- Verify reactor vessel flange and head flange temperatures are > 70°F.	In accordance with the Surveillance Frequency Control Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Reactor Steam Dome Pressure

LCO 3.4.10 The reactor steam dome pressure shall be ≤ 1020 psig.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Reactor steam dome pressure not within limit.	A.1	Restore reactor steam dome pressure to within limit.	15 minutes
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify reactor steam dome pressure is ≤ 1020 psig.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
G. Required Action and associated Completion Time of Condition C, D, E, or F not met. OR Two or more ADS valves inoperable.	G.1 AND G.2	Be in MODE 3. Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours
H. Two or more low pressure ECCS injection/spray subsystems inoperable for reasons other than condition A. OR HPCI System and one or more ADS valves inoperable.	H.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify, for each ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.2	----------NOTE---------- Low pressure coolant injection (LPCI) subsystems may be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the shutdown cooling permissive pressure in MODE 3, if capable of being manually realigned and not otherwise inoperable. ---------- Verify each ECCS injection/spray subsystem 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.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.3	Verify ADS pneumatic supply header pressure is ≥ 88 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.4	Verify the RHR System cross tie shutoff valve is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.5	----------NOTE---------- Not required to be performed if performed within the previous 31 days. ---------- Verify each recirculation pump discharge valve cycles through one complete cycle of full travel or is de-energized in the closed position.	Once each startup prior to exceeding 25% RTP

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.6	Verify the following ECCS pumps develop the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF Core Spray: ≥ 4720 gpm, 1, ≥ 113 psig LPCI: ≥ 15,000 gpm, 2, ≥ 20 psig	In accordance with the Inservice Testing Program
SR 3.5.1.7	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify, with reactor pressure ≤ 1020 and ≥ 920 psig, the HPCI pump can develop a flow rate ≥ 4250 gpm against a system head corresponding to reactor pressure.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.8	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify, with reactor pressure ≤ 165 psig, the HPCI pump can develop a flow rate ≥ 4250 gpm against a system head corresponding to reactor pressure.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.9	----------NOTES---------- 1. For HPCI only, not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. 2. Vessel injection/spray may be excluded. ----------	
	Verify each ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.10	----------NOTE---------- Valve actuation may be excluded. ----------	
	Verify the ADS actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.11	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ----------	
	Verify each ADS valve opens when manually actuated.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify, for each required ECCS injection/spray subsystem, the suppression pool water level is ≥ 12 ft 7 inches.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.2	Verify, for each required ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.3	----------NOTE---------- One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable. ----------	
	Verify each required ECCS injection/spray subsystem 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.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.4	Verify each required ECCS pump develops the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF CS / ≥ 4720 gpm / 1 / ≥ 113 psig LPCI / ≥ 7700 gpm / 1 / ≥ 20 psig	In accordance with the Inservice Testing Program
SR 3.5.2.5	----------NOTE---------- Vessel injection/spray may be excluded. ---------- Verify each required ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	Verify the RCIC System piping is filled with water from the pump discharge valve to the injection valve.	In accordance with the Surveillance Frequency Control Program
SR 3.5.3.2	Verify each RCIC System 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.	In accordance with the Surveillance Frequency Control Program
SR 3.5.3.3	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify, with reactor pressure ≤ 1020 psig and ≥ 920 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.	In accordance with the Surveillance Frequency Control Program
SR 3.5.3.4	----------NOTE---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify, with reactor pressure ≤ 165 psig, the RCIC pump can develop a flow rate ≥ 400 gpm against a system head corresponding to reactor pressure.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.3.5	----------NOTES---------- 1. Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. 2. Vessel injection may be excluded. ----------	
	Verify the RCIC System actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1.1	Perform required visual examinations and leakage rate testing except for primary containment air lock testing, in accordance with the Primary Containment Leakage Rate Testing Program.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.1.2	Verify drywell to suppression chamber bypass leakage is equivalent to a hole < 1.0 inch in diameter.	In accordance with the Surveillance Frequency Control Program AND ---------NOTE-------- Only required after two consecutive tests fail and continues until two consecutive tests pass ---------- 9 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.2.1	----------NOTES---------- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1.1. ---------- Perform required primary containment air lock leakage rate testing in accordance with the Primary Containment Leakage Rate Testing Program.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.2.2	Verify only one door in the primary containment air lock can be opened at a time.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.1	----------NOTES---------- 1. Not required to be met when the 24 inch primary containment purge and vent valves are open in one supply line and one exhaust line for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. 2. When the purging or venting in accordance with Note 1 is through the Standby Gas Treatment (SGT) System, both SGT subsystems shall be OPERABLE, and only one SGT subsystem shall be operating. ---------- Verify each 24 inch primary containment purge and vent valve is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.3.2	----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for PCIVs that are open under administrative controls. ---------- Verify each primary containment isolation manual valve and blind flange that is located outside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.3	----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for PCIVs that are open under administrative controls. ---------- Verify each primary containment manual isolation valve and blind flange that is located inside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	Prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days
SR 3.6.1.3.4	Verify continuity of the traversing incore probe (TIP) shear isolation valve explosive charge.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.3.5	Verify the isolation time of each power operated, automatic PCIV, except for MSIVs, is within limits.	In accordance with the Inservice Testing Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.6	Verify the isolation time of each MSIV is ≥ 3 seconds and ≤ 5 seconds.	In accordance with the Inservice Testing Program
SR 3.6.1.3.7	Verify each automatic PCIV actuates to the isolation position on an actual or simulated isolation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.3.8	Verify a representative sample of reactor instrumentation line EFCVs actuate to the isolation position on an actual or simulated instrument line break.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.3.9	Remove and test the explosive squib from each shear isolation valve of the TIP System.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.3.10	Verify leakage rate through each Main Steam line is ≤ 106 scfh when tested at ≥ 29 psig.	In accordance with the Primary Containment Leakage Rate Testing Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.11	Verify each inboard 24 inch primary containment purge and vent valve is blocked to restrict the maximum valve opening angle to 60°.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.3.12	Verify leakage rate through the Main Steam Pathway is ≤ 212 scfh when tested at ≥ 29 psig.	In accordance with the Primary Containment Leakage Rate Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.1.4 Drywell Pressure

LCO 3.6.1.4 Drywell pressure shall be ≤ 0.75 psig.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Drywell pressure not within limit.	A.1	Restore drywell pressure to within limit.	1 hour
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	AND		
	B.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.4.1	Verify drywell pressure is within limit.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.1.5 Drywell Air Temperature

LCO 3.6.1.5 Drywell average air temperature shall be ≤ 150°F.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Drywell average air temperature not within limit.	A.1	Restore drywell average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	AND		
	B.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.5.1	Verify drywell average air temperature is within limit.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.6.1	----------NOTES---------- Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. ---------- Verify each LLS valve opens when manually actuated.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.6.2	----------NOTES---------- Valve actuation may be excluded. ---------- Verify the LLS System actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two lines with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening.	D.1 Restore all vacuum breakers in one line to OPERABLE status.	1 hour
E. Required Action and Associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.7.1	----------NOTES---------- 1. Not required to be met for vacuum breakers that are open during Surveillances. 2. Not required to be met for vacuum breakers open when performing their intended function. ---------- Verify each vacuum breaker is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.7.2	Perform a functional test of each vacuum breaker.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.7.3	Verify the full open setpoint of each vacuum breaker is ≤ 0.5 psid.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.8.1	----------NOTES---------- Not required to be met for vacuum breakers that are open during Surveillances. ---------- Verify each vacuum breaker is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.8.2	Perform a functional test of each required vacuum breaker.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.8.3	Verify the opening setpoint of each required vacuum breaker is ≤ 0.5 psid.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.9.1	Verify each RHR containment spray subsystem 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 or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.6.1.9.2	Verify each required RHR pump develops a flow rate of > 7700 gpm through the associated heat exchanger while operating in the suppression pool cooling mode.	In accordance with the Inservice Testing Program
SR 3.6.1.9.3	Verify each spray nozzle is unobstructed.	Following maintenance which could result in nozzle blockage

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Suppression pool average temperature > 120°F.	E.1	Depressurize the reactor vessel to < 200 psig.	12 hours
	AND		
	E.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1.1	Verify suppression pool average temperature is within the applicable limits.	In accordance with the Surveillance Frequency Control Program AND 5 minutes when performing testing that adds heat to the suppression pool

3.6 CONTAINMENT SYSTEMS

3.6.2.2 Suppression Pool Water Level

LCO 3.6.2.2 Suppression pool water level shall be ≥ 12 ft 7 inches and ≤ 12 ft 11 inches.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Suppression pool water level not within limits.	A.1	Restore suppression pool water level to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	AND		
	B.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.2.1	Verify suppression pool water level is within limits.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.3.1	Verify each RHR suppression pool cooling subsystem 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 or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.6.2.3.2	Verify each RHR pump develops a flow rate > 7700 gpm through the associated heat exchanger while operating in the suppression pool cooling mode.	In accordance with the Inservice Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.3.1 Primary Containment Oxygen Concentration

LCO 3.6.3.1 The primary containment oxygen concentration shall be < 4.0 volume percent.

APPLICABILITY: MODE 1 during the time period:

a. From 24 hours after THERMAL POWER is > 15% RTP following startup, to

b. 24 hours prior to reducing THERMAL POWER to < 15% RTP prior to a reactor shutdown.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Primary containment oxygen concentration not within limit.	A.1	Restore oxygen concentration to within limit.	24 hours
B. Required Action and associated Completion Time not met.	B.1	Reduce THERMAL POWER to ≤ 15% RTP.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1.1	Verify primary containment oxygen concentration is within limits.	In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Initiate action to suspend OPDRVs.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.1	Verify secondary containment vacuum is ≥ 0.25 inch of vacuum water gauge.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.2	Verify all secondary containment equipment hatches are closed and sealed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.3	Verify one secondary containment access door in each access opening is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.4	Verify each SGT subsystem can maintain ≥ 0.25 inch of vacuum water gauge in the secondary containment for 1 hour at a flow rate ≤ 1780 cfm.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.2.1	----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for SCIVs that are open under administrative controls. ---------- Verify each secondary containment isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.2.2	Verify the isolation time of each power operated automatic SCIV is within limits.	In accordance with the Inservice Testing Program
SR 3.6.4.2.3	Verify each automatic SCIV actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. (continued)	E.2 Initiate action to suspend OPDRVs.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.3.1	Operate each SGT subsystem for ≥ 10 continuous hours with heaters operating.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.3.2	Perform required SGT filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.6.4.3.3	Verify each SGT subsystem actuates on an actual or simulated initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.3.4	Verify the SGT units cross tie damper is in the correct position, and each SGT room air supply check valve and SGT dilution air shutoff valve can be opened.	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 Both RHRSWB subsystems inoperable.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify each RHRSWB manual and power operated valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	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 Both SW subsystems inoperable. OR UHS inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	Verify the river water level is ≥ 865 ft mean sea level.	In accordance with the Surveillance Frequency Control Program
SR 3.7.2.2	Verify the average water temperature of UHS is ≤ 95°F.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.2.3	----------NOTE---------- Isolation of flow to individual components does not render SW System inoperable. ---------- Verify each SW subsystem manual, power operated, and automatic valve in the flow paths servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.2.4	Verify each SW subsystem actuates on an actual or simulated initiation signal.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	----------NOTES---------- 1. SR 3.0.1 is not applicable when both Service Water backup subsystems are OPERABLE. 2. REC system leakage beyond limits by itself is only a degradation of the REC system and does not result in the REC system being inoperable. ---------- Verify the REC system leakage is within limits.	In accordance with the Surveillance Frequency Control Program
SR 3.7.3.2	Verify the temperature of the REC supply water is ≤ 100°F.	In accordance with the Surveillance Frequency Control Program
SR 3.7.3.3	----------NOTE---------- Isolation of flow to individual components does not render REC System inoperable. ---------- Verify each REC subsystem manual, power operated, and automatic valve in the flow paths servicing safety related cooling loads, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.3.4	Verify each REC subsystem actuates on an actual or simulated initiation signal.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Operate the CREF System for ≥ 15 minutes.	In accordance with the Surveillance Frequency Control Program
SR 3.7.4.2	Perform required CREF filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP.
SR 3.7.4.3	Verify the CREF System actuates on an actual or simulated initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.7.4.4	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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	----------NOTES---------- Not required to be performed until 31 days after any main steam line not isolated and SJAE in operation. ----------	
	Verify the gross gamma activity rate of the noble gases is ≤ 1.0 Ci/second.	In accordance with the Surveillance Frequency Control Program AND Once within 4 hours after a ≥ 50% increase in the nominal steady state fission gas release after factoring out increases due to changes in THERMAL POWER level.

3.7 PLANT SYSTEMS

3.7.6 Spent Fuel Storage Pool Water Level

LCO 3.7.6 The spent fuel storage pool water level shall be ≥ 21 ft 6 inches over the top of irradiated fuel assemblies seated in the spent fuel storage pool racks.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spent 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 spent fuel storage pool.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify the spent fuel storage pool water level is ≥ 21 ft 6 inches over the top of irradiated fuel assemblies seated in the spent fuel storage pool racks.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	Verify operation of each main turbine bypass valve.	In accordance with the Surveillance Frequency Control Program
SR 3.7.7.2	Perform a system functional test.	In accordance with the Surveillance Frequency Control Program
SR 3.7.7.3	Verify the TURBINE BYPASS SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.2	----------NOTE---------- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. ----------	
	Verify each DG starts from standby conditions and achieves steady state voltage ≥ 3950 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	----------NOTE---------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow, without shutdown, a successful performance of SR 3.8.1.2 or SR 3.8.1.7. ---------- Verify each DG is synchronized and loaded and operates for ≥ 2 hours at a load ≥ 3600 kW and ≤ 4000 kW.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.4	Verify each day tank contains ≥ 1500 gal of fuel oil.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tanks to the day tanks.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.7	----------NOTE---------- All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts from standby condition and achieves, in ≤ 14 seconds, voltage ≥ 3950 V and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 3950 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.8	----------NOTE---------- This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify automatic and manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTE---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. 3. If performed with DG synchronized with offsite power, the surveillance shall be performed at a power factor ≤ 0.89. 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 DG operates for ≥ 8 hours: a. For ≥ 2 hours loaded ≥ 4200 kW and ≤ 4400 kW; and b. For the remaining hours of the test loaded ≥ 3600 kW and ≤ 4000 kW.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.10	----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2 or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify interval between each sequenced load is within ± 10% of nominal timer setpoint.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	----------NOTE---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 14 seconds, 2. energizes auto-connected emergency loads through the timed logic sequence, 3. maintains steady state voltage ≥ 3950 V and ≤ 4400 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify the fuel oil storage tanks contain a combined volume of ≥ 49,500 gal of fuel.	In accordance with the Surveillance Frequency Control Program
SR 3.8.3.2	Verify lube oil inventory is ≥ 504 gal.	In accordance with the Surveillance Frequency Control Program
SR 3.8.3.3	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 3.8.3.4	Verify each DG has a minimum of one air start receiver with a pressure ≥ 200 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.8.3.5	Check for and remove accumulated water from each fuel oil storage tank.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage on float charge is: a. ≥ 125.9 V for the 125 V batteries; and b. ≥ 260.4 V for the 250 V batteries.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.2	Verify no visible corrosion at battery terminals and connectors. OR Verify battery connection resistance meets the limits specified in Table 3.8.4-1.	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 degrades battery performance.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.4	Remove visible corrosion and verify battery cell to cell and terminal connections are coated with anti-corrosion material.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.5	Verify battery connection resistance meets the limits specified in Table 3.8.4-1.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.6	Verify: a. Each required 125 V battery charger supplies ≥ 200 amps at ≥ 125 V for ≥ 4 hours; and b. Each required 250 V battery charger supplies ≥ 200 amps at ≥ 250 V for ≥ 4 hours.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.7	----------NOTE---------- 1. The modified performance discharge test in SR 3.8.4.8 may be performed in lieu of the service test in SR 3.8.4.7. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ----------	
	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.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.8	----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ----------	
	Verify battery capacity is ≥ 90% of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	In accordance with the Surveillance Frequency Control Program 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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Restore battery cell parameters to Category A and B limits of Table 3.8.6-1.	31 days
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 not within limits. OR One or more batteries with one or more battery cell parameters not within Category C limits.	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.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.6.2	Verify battery cell parameters meet Table 3.8.6-1 Category B limits.	In accordance with the Surveillance Frequency Control Program AND Once within 24 hours after battery discharge < 105 V for a 125 V battery or < 210 V for a 250 V battery AND Once within 24 hours after battery overcharge > 140 V for a 125 V battery or > 280 V for a 250 V battery
SR 3.8.6.3	Verify average electrolyte temperature of representative cells is ≥ 70°F.	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.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. One or more 250 V DC electrical power distribution subsystems inoperable.	D.1 Declare associated supported feature(s) inoperable.	Immediately
E. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.4 Initiate actions to restore required AC and DC electrical power distribution subsystems to OPERABLE status.	Immediately
	AND	
	A.2.5 Declare associated required shutdown cooling subsystem(s) inoperable and not in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct breaker alignments and voltage to required AC and DC electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Perform CHANNEL FUNCTIONAL TEST on each of the following required refueling equipment interlock inputs: a. All-rods-in, b. Refuel platform position, c. Refuel platform fuel grapple, fuel loaded, d. Refuel platform fuel grapple not full up, e. Refuel platform frame mounted hoist, fuel loaded, f. Refuel platform monorail mounted hoist, fuel loaded, and g. Service platform hoist, fuel loaded.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.2 Refuel Position One-Rod-Out Interlock

LCO 3.9.2 The refuel position one-rod-out interlock shall be OPERABLE.

APPLICABILITY: MODE 5 with the reactor mode switch in the refuel position and any control rod withdrawn.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Refuel position one-rod-out interlock inoperable.	A.1	Suspend control rod withdrawal.	Immediately
	AND		
	A.2	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Verify reactor mode switch locked in refuel position.	In accordance with the Surveillance Frequency Control Program
SR 3.9.2.2	----------NOTE---------- Not required to be performed until 1 hour after any control rod is withdrawn. ----------	
	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.3 Control Rod Position

LCO 3.9.3 All control rods shall be fully inserted.

APPLICABILITY: When loading fuel assemblies into the core.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more control rods not fully inserted.	A.1 Suspend loading fuel assemblies into the core.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Verify all control rods are fully inserted.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.5 Control Rod OPERABILITY - Refueling

LCO 3.9.5 Each withdrawn control rod shall be OPERABLE.

APPLICABILITY: MODE 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more withdrawn control rods inoperable.	A.1 Initiate action to fully insert inoperable withdrawn control rods.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	----------NOTE---------- Not required to be performed until 7 days after the control rod is withdrawn. ---------- Insert each withdrawn control rod at least one notch.	In accordance with the Surveillance Frequency Control Program
SR 3.9.5.2	Verify each withdrawn control rod scram accumulator pressure is ≥ 940 psig.	In accordance with the Surveillance Frequency Control Program

3.9 REFUELING OPERATIONS

3.9.6 Reactor Pressure Vessel (RPV) Water Level

LCO 3.9.6 RPV water level shall be ≥ 21 ft above the top of the RPV flange.

APPLICABILITY: During movement of irradiated fuel assemblies within the RPV,
During movement of new fuel assemblies or handling of control rods within the RPV, when irradiated fuel assemblies are seated within the RPV.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. RPV water level not within limit.	A.1	Suspend movement of fuel assemblies and handling of control rods within the RPV.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify RPV water level is ≥ 21 ft above the top of the RPV flange.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.7.1	Verify one RHR shutdown cooling subsystem is operating.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.8.1	Verify one RHR shutdown cooling subsystem is operating.	In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3.1 Place the reactor mode switch in the shutdown position.	1 hour
	OR	
	A.3.2 ----------NOTE---------- Only applicable in MODE 5. ---------- Place the reactor mode switch in the refuel position.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.2.1	Verify all control rods are fully inserted in core cells containing one or more fuel assemblies.	In accordance with the Surveillance Frequency Control Program
SR 3.10.2.2	Verify no CORE ALTERATIONS are in progress.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.3.1	Perform the applicable SRs for the required LCOs.	According to the applicable SRs
SR 3.10.3.2	----------NOTE---------- Not required to be met if SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements. ---------- Verify all control rods, other than the control rod being withdrawn, in a five by five array centered on the control rod being withdrawn, are disarmed.	In accordance with the Surveillance Frequency Control Program
SR 3.10.3.3	Verify all control rods, other than the control rod being withdrawn, are fully inserted.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.10.4.2	----------NOTE---------- Not required to be met if SR 3.10.4.1 is satisfied for LCO 3.10.4.c.1 requirements. ---------- Verify all control rods, other than the control rod being withdrawn, in a five by five array centered on the control rod being withdrawn, are disarmed.	In accordance with the Surveillance Frequency Control Program
SR 3.10.4.3	Verify all control rods, other than the control rod being withdrawn, are fully inserted.	In accordance with the Surveillance Frequency Control Program
SR 3.10.4.4	----------NOTE---------- Not required to be met if SR 3.10.4.1 is satisfied for LCO 3.10.4.b.1 requirements. ---------- Verify a control rod withdrawal block is inserted.	In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.1 Initiate action to fully insert all control rods. OR A.2.2 Initiate action to satisfy the requirements of this LCO.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.5.1	Verify all control rods, other than the control rod withdrawn for the removal of the associated CRD, are fully inserted.	In accordance with the Surveillance Frequency Control Program
SR 3.10.5.2	Verify all control rods, other than the control rod withdrawn for the removal of the associated CRD, in a five by five array centered on the control rod withdrawn for the removal of the associated CRD, are disarmed.	In accordance with the Surveillance Frequency Control Program
SR 3.10.5.3	Verify a control rod withdrawal block is inserted.	In accordance with the Surveillance Frequency Control Program
SR 3.10.5.4	Perform SR 3.1.1.1.	According to SR 3.1.1.1

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.10.5.5	Verify no other CORE ALTERATIONS are in progress.	In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3.1 Initiate action to fully insert all control rods in core cells containing one or more fuel assemblies. OR A.3.2 Initiate action to satisfy the requirements of this LCO.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.6.1	Verify the four fuel assemblies are removed from core cells associated with each control rod or CRD removed.	In accordance with the Surveillance Frequency Control Program
SR 3.10.6.2	Verify all other control rods in core cells containing one or more fuel assemblies are fully inserted.	In accordance with the Surveillance Frequency Control Program
SR 3.10.6.3	----------NOTE---------- Only required to be met during fuel loading. ---------- Verify fuel assemblies being loaded are in compliance with an approved spiral reload sequence.	 In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.10.8.2	----------NOTE---------- Not required to be met if SR 3.10.8.3 satisfied. ---------- Perform the MODE 2 applicable SRs for LCO 3.3.2.1, Function 2 of Table 3.3.2.1-1.	According to the applicable SRs
SR 3.10.8.3	----------NOTE---------- Not required to be met if SR 3.10.8.2 satisfied. ---------- Verify movement of control rods is in compliance with the approved control rod sequence for the SDM test by a second licensed operator or other qualified member of the technical staff.	During control rod movement
SR 3.10.8.4	Verify no other CORE ALTERATIONS are in progress.	In accordance with the Surveillance Frequency Control Program
SR 3.10.8.5	Verify each withdrawn control rod does not go to the withdrawn overtravel position.	Each time the control rod is withdrawn to "full out" position <u>AND</u> Prior to satisfying LCO 3.10.8.c requirement after work on control rod or CRD System that could affect coupling

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.10.8.6	Verify CRD charging water header pressure ≥ 940 psig.	In accordance with the Surveillance Frequency Control Program

5.5 Programs and Manuals

5.5.13 Control Room Envelope Habitability Program (continued)

personnel receiving radiation exposures in excess of either (a) 5 rem whole body or its equivalent to any part of the body for the duration of the loss-of-coolant accident, or (b) 5 rem total effective dose equivalent (TEDE) for the duration of the fuel handling accident. The program shall include the following elements:

a. The definition of the CRE and CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0. No exceptions to Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0, are proposed.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by the CREF System, operating at the flow rate required by the Ventilation Filter Testing Program, at a Frequency of 24 months. The results shall be trended and used as part of the periodic assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered air inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

(continued)

5.5 Programs and Manuals (continued)

5.5.14 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 Operation 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 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 (Deleted)

5.6.2 Annual Radiological Environmental Report

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the radiological environmental monitoring program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Assessment Manual (ODAM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODAM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in Regulatory Guide 4.8, December 1975. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

(continued)

5.6 Reporting Requirements (continued)

5.6.3 Radioactive Effluent Release Report

The Radioactive Effluent Release Report covering the operation of the unit shall be submitted in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODAM and the Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.6.4 (Deleted)

5.6.5 Core Operating Limits Report (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. The Average Planar Linear Heat Generation Rates for Specifications 3.2.1 and 3.7.7.

2. The Minimum Critical Power Ratio for Specifications 3.2.2 and 3.7.7.

3. The Linear Heat Generation Rates for Specifications 3.2.3 and 3.7.7.

4. The three Rod Block Monitor Upscale Allowable Values for Specification 3.3.2.1.

5. The power/flow map defining the Stability Exclusion Region for Specification 3.4.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (Revision specified in the COLR).

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

2. NEDE-23785-1-P-A, "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident", Volume III, Revision 1, October 1984.

3. NEDO-31960 and NEDO-31960 Supplement 1, "BWR Owner's Group Long-Term Stability Solutions Licensing Methodology" (the approved Revision at the time the reload analysis is performed).

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 Post Accident Monitoring (PAM) Instrumentation Report

When a report is required by Condition B or F of LCO 3.3.3.1, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

5.7.1 In lieu of the "control device" or "alarm signal" required by paragraph 20.1601 of 10 CFR Part 20, each high radiation area in which the deep dose equivalent in excess of 100 mrem but less than 1000 mrem in one hour (measurement made at 12 inches from source of radiation) shall be barricaded (barricade will impede physical movement across the entrance or access to the high radiation area; i.e., doors, yellow and magenta rope, turnstile) and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Special Work Permit (SWP). Radiation protection personnel or personnel escorted by radiation protection personnel shall be exempt from the SWP issuance requirement during the performance of their assigned duties, provided they are otherwise following plant radiation protection procedures for entry into high radiation areas. Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

a. A monitoring device which continuously indicates the radiation dose rate in the area.

b. A monitoring device which continuously integrates the radiation dose in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rates in the area have been established and personnel have been made knowledgeable of them.

c. A radiation protection qualified individual (i.e., qualified in radiation protection procedures), with a dose rate monitoring device, who is responsible for providing positive control over the activities within the area and shall perform periodic dose rate monitoring at the frequency specified by Health Physics supervision.

5.7.2 In addition to the requirements of Specification 5.7.1, areas accessible to personnel with dose rates such that a major portion of the body could receive in 1 hour a deep dose equivalent in excess of 1000 mrem (measurement made at 12 inches from source of radiation) shall be provided with locked doors to prevent unauthorized entry. Doors shall remain locked except during periods of access by personnel under an approved SWP which shall specify the dose rates in the immediate work area. For individual high radiation areas accessible to personnel that are located within large areas, such as the containment, or areas where no enclosure exists for purposes of locking and no enclosure can be reasonably constructed around the individual areas, then that area shall be barricaded and conspicuously posted. Area radiation monitors that have been set to alarm if radiation levels increase, provide both a visual and an audible signal to alert personnel in the area of the increase. These monitors may be used to meet Specification 5.7.1.a provided that the dose rates and alarms have been established by radiation protection personnel. Stay times or continuous surveillance, direct or remote (such as use of closed circuit TV cameras), may be made by personnel qualified in radiation protection procedures to provide additional positive exposure control over the activities within the area.

Attachment 5

Proposed Technical Specification Bases Changes (Information Only)

Cooper Nuclear Station, Docket No. 50-298, License No. DPR-46

Revised Technical Specification Bases Pages

B 3.1-19	B 3.3-117	B 3.5-16	B 3.7-29
B 3.1-20	B 3.3-118	B 3.5-22	B 3.7-33
B 3.1-26	B 3.3-119	B 3.5-27	B 3.7-34
B 3.1-33	B 3.3-129	B 3.5-28	B 3.8-15
B 3.1-37	B 3.3-130	B 3.5-29	B 3.8-16
B 3.1-42	B 3.3-131	B 3.6-5	B 3.8-17
B 3.1-43	B 3.3-154	B 3.6-13	B 3.8-18
B 3.1-44	B 3.3-155	B 3.6-24	B 3.8-19
B 3.1-45	B 3.3-156	B 3.6-26	B 3.8-20
B 3.1-49	B 3.3-165	B 3.6-27	B 3.8-21
B 3.1-50	B 3.3-166	B 3.6-28	B 3.8-22
B 3.2-3	B 3.3-172	B 3.6-31	B 3.8-33
B 3.2-6	B 3.3-173	B 3.6-34	B 3.8-34
B 3.2-10	B 3.3-180	B 3.6-37	B 3.8-36
B 3.3-23	B 3.3-181	B 3.6-38	B 3.8-41
B 3.3-24	B 3.3-190	B 3.6-43	B 3.8-42
B 3.3-25	B 3.3-191	B 3.6-44	B 3.8-43
B 3.3-26	B 3.3-197	B 3.6-49	B 3.8-44
B 3.3-27	B 3.3-198	B 3.6-50	B 3.8-45
B 3.3-28	B 3.4-7	B 3.6-54	B 3.8-46
B 3.3-29	B 3.4-12	B 3.6-55	B 3.8-52
B 3.3-30	B 3.4-17	B 3.6-56	B 3.8-62
B 3.3-36	B 3.4-23	B 3.6-59	B 3.8-66
B 3.3-37	B 3.4-27	B 3.6-63	B 3.9-4
B 3.3-38	B 3.4-28	B 3.6-66	B 3.9-8
B 3.3-39	B 3.4-32	B 3.6-70	B 3.9-11
B 3.3-50	B 3.4-37	B 3.6-71	B 3.9-18
B 3.3-51	B 3.4-43	B 3.6-77	B 3.9-21
B 3.3-52	B 3.4-49	B 3.6-78	B 3.9-25
B 3.3-53	B 3.4-50	B 3.6-83	B 3.9-26
B 3.3-54	B 3.4-51	B 3.6-84	B 3.9-30
B 3.3-59	B 3.4-54	B 3.7-5	B 3.10-10
B 3.3-60	B 3.5-9	B 3.7-9	B 3.10-15
B 3.3-69	B 3.5-10	B 3.7-10	B 3.10-20
B 3.3-70	B 3.5-11	B 3.7-14	B 3.10-25
B 3.3-74	B 3.5-12	B 3.7-15	B 3.10-28
B 3.3-75	B 3.5-13	B 3.7-16	B 3.10-29
B 3.3-85	B 3.5-14	B 3.7-22	B 3.10-38
B 3.3-86	B 3.5-15	B 3.7-27	B 3.10-39

INSERT 2

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

BASES

ACTIONS (continued)

active function (i.e., scram) of the control rods. The number of control rods permitted to be inoperable when operating above 9.85 RTP (e.g., no CRDA considerations) could be more than the value specified, but the occurrence of a large number of inoperable control rods could be indicative of a generic problem, and investigation and resolution of the potential problem should be undertaken. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The position of each control rod must be determined to ensure adequate information on control rod position is available to the operator for determining control rod OPERABILITY and controlling rod patterns. Control rod position may be determined by the use of OPERABLE position indicators, by moving control rods to a position with an OPERABLE indicator, or by the use of other appropriate methods. ~~The 24 hour Frequency of this SR is based on operating experience related to expected changes in control rod position and the availability of control rod position indications in the control room.~~ INSERT 2

SR 3.1.3.2 (Deleted)

SR 3.1.3.3

Control rod insertion capability is demonstrated by inserting each partially or fully withdrawn control rod at least one notch and observing that the control rod moves. The control rod may then be returned to its original position. This ensures the control rod is not stuck and is free to insert on a scram signal. This Surveillance is not required when THERMAL POWER is less than or equal to the actual LPSP of the RWM, since the notch insertions may not be compatible with the requirements of the Banked Position Withdrawal Sequence (BPWS) (LCO 3.1.6) and the RWM (LCO 3.3.2.1). ~~Withdrawn control~~

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~rods are tested at a 31 day Frequency, based on the potential power reduction required to allow the control rod movement. Furthermore, the 31 day Frequency takes into account operating experience related to changes in CRD performance.~~ At any time, if a control rod is immovable, a determination of that control rod's capability of insertion by scram (OPERABILITY) must be made and appropriate action taken. INSERT 2

This SR is modified by a Note that allows 31 days after withdrawal of the control rod and increasing power to above the LPSP, to perform the Surveillance. This acknowledges that the control rod must be first withdrawn and THERMAL POWER must be increased to above the LPSP before performance of the Surveillance, and therefore the Notes avoid potential conflicts with SR 3.0.3 and SR 3.0.4.

SR 3.1.3.4

Verifying that the scram time for each control rod to notch position 06 is $\leq$ 7 seconds provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown function. This SR is performed in conjunction with the control rod scram time testing of SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and the functional testing of SDV vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlap this Surveillance to provide complete testing of the assumed safety function. The associated Frequencies are acceptable, considering the more frequent testing performed to demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.2

Additional testing of a sample of control rods is required to verify the continued performance of the scram function during the cycle. A representative sample contains at least 10% of the control rods. The sample remains representative if no more than 7.5% of the control rods in the sample tested are determined to be "slow." With more than 7.5% of the sample declared to be "slow" per the criteria in Table 3.1.4-1, additional control rods are tested until this 7.5% criterion (i.e., 7.5% of the entire sample size) is satisfied, or until the total number of "slow" control rods (throughout the core, from all surveillances) exceeds the LCO limit. For planned testing, the control rods selected for the sample should be different for each test. Data from inadvertent scrams should be used whenever possible to avoid unnecessary testing at power, even if the control rods with data may have been previously tested in a sample. ~~The 200 day Frequency is based on operating experience that has shown control rod scram times do not significantly change over an operating cycle. This Frequency is also reasonable based on the additional Surveillances done on the CRDs at more frequent intervals in accordance with LCO 3.1.3 and LCO 3.1.5, "Control Rod Scram Accumulators."~~ INSERT 2

SR 3.1.4.3

When work that could affect the scram insertion time is performed on a control rod or the CRD System, testing must be done to demonstrate that each affected control rod retains adequate scram performance over the range of applicable reactor pressures from zero to the maximum permissible pressure. The scram testing must be performed once before declaring the control rod OPERABLE. The required scram time testing must demonstrate the affected control rod is still within acceptable limits. The limits for reactor pressures < 800 psig are found in the Technical Requirements Manual (Ref. 8) and are established based on a high probability of meeting the acceptance criteria at reactor pressures ≥ 800 psig. Limits for ≥ 800 psig are found in Table 3.1.4-1. If testing demonstrates the affected control rod does not meet these limits, but is within the 7-second limit of Table 3.1.4-1, Note 2, the control rod can be declared OPERABLE and "slow."

BASES

ACTIONS

D.1 (continued)

ensures that all insertable control rods are inserted and that the reactor is in a condition that does not require the active function (i.e., scram) of the control rods. This Required Action is modified by a Note stating that the action is not applicable if all control rods associated with the inoperable scram accumulators are fully inserted, since the function of the control rods has been performed.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

periodically

SR 3.1.5.1 requires that the accumulator pressure be checked ~~every 7 days~~ to ensure adequate accumulator pressure exists to provide sufficient scram force. The primary indicator of accumulator OPERABILITY is the accumulator pressure. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of 940 psig is well below the expected pressure of 1100 psig. Declaring the accumulator inoperable when the minimum pressure is not maintained ensures that significant degradation in scram times does not occur. ~~The 7-day Frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.~~

INSERT 2

REFERENCES

1. USAR, Section III-5.
2. USAR, Section VII-2.
3. USAR, Appendix F.
4. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

B.1 and B.2

If nine or more OPERABLE control rods are out of sequence, the control rod pattern significantly deviates from the prescribed sequence. Control rod withdrawal should be suspended immediately to prevent the potential for further deviation from the prescribed sequence. Control rod insertion to correct control rods withdrawn beyond their allowed position is allowed since, in general, insertion of control rods has less impact on control rod worth than withdrawals have. Required Action B.1 is modified by a Note which allows the RWM to be bypassed to allow the affected control rods to be returned to their correct position. LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator (Reactor Operator or Senior Reactor Operator) or by a qualified member of the technical staff.

When nine or more OPERABLE control rods are not in compliance with BPWS, the reactor mode switch must be placed in the shutdown position within 1 hour. With the mode switch in shutdown, the reactor is shut down, and as such, does not meet the applicability requirements of this LCO. The allowed Completion Time of 1 hour is reasonable to allow insertion of control rods to restore compliance, and is appropriate relative to the low probability of a CRDA occurring with the control rods out of sequence.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

periodically

The control rod pattern is verified to be in compliance with the BPWS ~~at a 24 hour Frequency~~ to ensure the assumptions of the CRDA analyses are met. ~~The 24 hour Frequency was developed considering that the primary check on compliance with the BPWS is performed by the RWM (LCO 3.3.2.1), which~~ provides control rod blocks to enforce the required sequence and is required to be OPERABLE when operating at ≤ 9.85% RTP.

INSERT 2

The RWM

BASES

ACTIONS (continued)

C.1 and C.2

If any Required Action and associated Completion Time is 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 MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1, SR 3.1.7.2, and SR 3.1.7.3

SR 3.1.7.1 through SR 3.1.7.3 ~~are 24 hour Surveillances~~ verify~~ing~~ certain characteristics of the SLC System (e.g., the volume and temperature of the borated solution in the storage tank), thereby ensuring SLC System OPERABILITY without disturbing normal plant operation. These Surveillances ensure that the proper borated solution volume and temperature, including the temperature of the pump suction piping, are maintained. Maintaining a minimum specified borated solution temperature is important in ensuring that the boron remains in solution and does not precipitate out in the storage tank or in the pump suction piping. The temperature versus concentration curve of Figure 3.1.7-2 ensures that a 10°F margin will be maintained above the saturation temperature. ~~The 24 hour Frequency is based on operating experience and has shown there are relatively slow variations in the measured parameters of volume and temperature.~~ INSERT 2

SR 3.1.7.4 and SR 3.1.7.6

SR 3.1.7.4 verifies the continuity of the explosive charges in the injection valves to ensure that proper operation will occur if required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. ~~The 31 day Frequency is based on operating experience and has demonstrated the reliability of the explosive charge continuity.~~ INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.6 verifies that each valve in the system is in its correct position, but does not apply to the squib (i.e., explosive) valves. Verifying the correct alignment for manual valves in the SLC System flow path provides assurance that the proper flow paths will exist for system operation. A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position from the control room, or locally by a dedicated operator at the valve control. This is acceptable since the SLC System is a manually initiated system. This Surveillance also 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 verification of valve alignment 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 31 day Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation that ensures correct valve positions.~~ INSERT 2

SR 3.1.7.5

This Surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure that the proper concentration of boron in the storage tank is maintained per Figure 3.1.7-1. SR 3.1.7.5 must be performed anytime boron or water is added to the storage tank solution to determine that the boron solution concentration is within the specified limits. SR 3.1.7.5 must also be performed anytime the temperature is restored to within the limits of Figure 3.1.7-2, to ensure that no significant boron precipitation occurred. ~~The 31 day Frequency of this Surveillance is appropriate because of the relatively slow variation of boron concentration between surveillances.~~ INSERT 2

SR 3.1.7.7

Demonstrating that each SLC System pump develops a flow rate $\geq$ 38.2 gpm at a discharge pressure $\geq$ 1300 psig, by recirculating demineralized water to the test tank, ensures that pump performance has not degraded during the fuel cycle. This minimum pump flow rate requirement ensures that, when combined with the sodium pentaborate solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the

BASES

SURVEILLANCE REQUIREMENTS (continued)

positive reactivity effects encountered during power reduction, cooldown of the moderator, and xenon decay. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, and detect incipient failures by indicating abnormal performance. The Frequency of this Surveillance is in accordance with the Inservice Testing Program.

SR 3.1.7.8 and SR 3.1.7.9

These Surveillances ensure that there is a functioning flow path from the boron solution storage tank to the RPV, including the firing of an explosive valve. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of that batch successfully fired. ~~The pump and explosive valve tested should be alternated such that both complete flow paths are tested every 48 months at alternating 24 month intervals~~. The Surveillance may be performed in separate steps to prevent injecting boron into the RPV. An acceptable method for verifying flow from the pump to the RPV is to pump demineralized water from a test tank through one SLC subsystem and into the RPV. ~~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 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 at the 24 month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

Demonstrating that all heat traced piping between the boron solution storage tank and the suction inlet to the injection pumps is unblocked ensures that there is a functioning flow path for injecting the sodium pentaborate solution. An acceptable method for verifying that the suction piping is unblocked is to manually initiate the system, except the explosive valves, and pump from the storage tank to the test tank. Upon completion of this verification, the pump suction piping must be flushed with demineralized water to ensure piping between the storage tank and pump suction is unblocked. ~~The 24 month Frequency is acceptable since there is a low probability that the subject piping will be blocked due to precipitation of the boron from solution in the heat traced piping. This is especially true in light of the temperature verification of this piping.~~ INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~required by SR 3.1.7.3. However, if, in~~ In performing SR 3.1.7.3, it is determined that the temperature of this piping has fallen below the specified minimum, SR 3.1.7.9 must be performed once within 24 hours after the piping temperature is restored to within the limits of Figure 3.1.7-2.

REFERENCES

1. 10 CFR 50.62.

2. USAR, Section III-9.

3. 10 CFR 50.36(c)(2)(ii).

4. NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants, February 1995."

5. 10 CFR 50.67, "Accident Source Term."

BASES

ACTIONS

B.1 (continued)

The 8 hour Completion Time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and unlikelihood of significant CRD seal leakage.

C.1

If any Required Action and associated Completion Time is 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 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

During normal operation, the SDV vent and drain valves should be in the open position (except when performing SR 3.1.8.2) to allow for drainage of the SDV piping. Verifying that each valve is in the open position ensures that the SDV vent and drain valves will perform their intended functions during normal operation. This SR does not require any testing or valve manipulation; rather, it involves verification that the valves are in the correct position.

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

INSERT 2

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.8.2

During a scram, the SDV vent and drain valves should close to contain the reactor water discharged to the SDV piping. Cycling each valve through its complete range of motion (closed and open) ensures that the valve will function properly during a scram. ~~The 92 day Frequency is based on operating experience and takes into account the level of redundancy in the system design.~~ INSERT 2

SR 3.1.8.3

SR 3.1.8.3 is an integrated test of the SDV vent and drain valves to verify total system performance. After receipt of a simulated or actual scram signal, the closure of the automatic SDV vent and drain valves is verified. The closure time of 30 seconds after receipt of a scram signal is based on the bounding leakage case evaluated in the accident analysis. Similarly, after receipt of a simulated or actual scram reset signal, the opening of the SDV vent and drain valves is verified. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1 and the scram time testing of control rods in LCO 3.1.3, "Control Rod Operability," overlap this Surveillance to provide complete testing of the assumed safety function. ~~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 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 at the 24 month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

periodically

APLHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and ~~then every 24 hours~~ thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. ~~The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation.~~ The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

INSERT 2

REFERENCES

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," (Revision specified in the COLR).

2. Deleted.

3. USAR, Section VI.

4. USAR, Section XIV.

5. NEDO-24258, "Cooper Nuclear Station Single-Loop Operation," May 1980.

6. NEDC-32914P, "Maximum Extended Load Line Limit and Increased Core Flow for Cooper Nuclear Station," Revision 0, January 2000.

7. Deleted.

8. Deleted.

9. NEDC-32687P, Revision 1, "Cooper Nuclear Station SAFER/ GESTR-LOCA Loss-of-Coolant Accident Analysis," March 1997.

10. NEDE-23785-1-PA, "The GESTR-LOCA and SAFER Models for the Evaluation of Loss-of-Coolant Accident," Volume III, Revision 1, October 1984.

11. Deleted.

12. 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABILITY (continued)

< 25% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

ACTIONS

A.1

If any MCPR is outside the required limits, an assumption regarding an initial condition of the design basis transient analyses may not be met. Therefore, prompt action should be taken to restore the MCPR(s) to within the required limits such that the plant remains operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the MCPR(s) to within its limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the MCPR out of specification.

B.1

If the MCPR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

periodically

The MCPR is required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and ~~then every 24 hours~~ thereafter. It is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. ~~The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation.~~ The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

INSERT 2

BASES

APPLICABILITY

The LHGR limits are derived from fuel design analysis that is limiting at high power level conditions. At core thermal power levels < 25% RTP, the reactor is operating with a substantial margin to the LHGR limits and, therefore, the Specification is only required when the reactor is operating at ≥ 25% RTP.

ACTIONS

A.1

If any LHGR exceeds its required limit, an assumption regarding an initial condition of the fuel design analysis is not met. Therefore, prompt action should be taken to restore the LHGR(s) to within its required limits such that the plant is operating within analyzed conditions and within the design limits of the fuel rods. The 2 hour Completion Time is normally sufficient to restore the LHGR(s) to within its limits and is acceptable based on the low probability of a transient or LOCA occurring simultaneously with the LHGR out of specification.

B.1

If the LHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER is reduced to < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

The LHGR is required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and ~~then every 24 hours~~ periodically thereafter. It is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. ~~The 24 hour Frequency is based on both engineering judgment and recognition of the slow changes in power distribution during normal operation.~~ The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at lower power levels.

INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.1

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 instrument channels could be an indication of excessive instrument drift on one of the channels or 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.

Agreement criteria are determined by the plant 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 instrument has drifted outside its limit.

~~The Frequency is based upon 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 channels required by the LCO.

INSERT 2

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. ~~The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.8.~~

INSERT 2

A restriction to satisfying this SR when < 25% RTP is provided that requires the SR to be met only at ≥ 25% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR and APLHGR). At ≥ 25% RTP, the Surveillance is required to have been satisfactorily performed ~~within the last 7 days~~, in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 25% if the ~~7 day~~ Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 25% RTP. Twelve hours is based on

BASES

SURVEILLANCE REQUIREMENTS (continued)

operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.3 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the ~~7 day~~ Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

~~A Frequency of 7 days provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. 11).~~ INSERT 2

SR 3.3.1.1.4

There are four RPS channel test switches, one associated with each of the four automatic scram logic channels (A1, A2, B1, and B2). These keylock switches allow the operator to test the OPERABILITY of each individual logic channel (i.e., test through the K14 relay) without the necessity of using a scram function trip. This is accomplished by placing the RPS channel test switch in test, which will input a trip signal into the associated RPS logic channel. The RPS channel test switches are not specifically credited in the accident analysis. However, because the Manual Scram Functions at CNS were not configured the same as the generic model in Reference 11, the RPS channel test switches were included in the analysis in Reference 12. Reference 12 concluded that the

BASES

SURVEILLANCE REQUIREMENTS (continued)

Surveillance Frequency extensions for RPS Functions, described in Reference 11, were not affected by the difference in configuration, since each automatic RPS channel has a test switch which is functionally the same as the manual scram switches in the generic model. ~~As such, a functional test of each RPS channel test switch is required to be performed once every 7 days. The Frequency of 7 days is based on the reliability analysis of Reference 12.~~ INSERT 2

SR 3.3.1.1.5 and SR 3.3.1.1.6

These Surveillances are established to ensure that no gaps in neutron flux indication exist from subcritical to power operation for monitoring core reactivity status.

The overlap between SRMs and IRMs is required to be demonstrated to ensure that reactor power will not be increased into a neutron flux region without adequate indication. This is required prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs.

The overlap between IRMs and APRMs is of concern when reducing power into the IRM range. On power increases, the system design will prevent further increases (by initiating a rod block) if adequate overlap is not maintained. Overlap between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have onscale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block, or IRM upscale rod block. On controlled shutdowns, the IRM reading 121/125 of full scale will be set equal to or less than 45% of rated power. All range scales above that scale on which the most recent IRM calibration was performed will be mechanically blocked. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, all operable IRM channels shall be on scale.

As noted, SR 3.3.1.1.6 is only required to be met during entry into MODE 2 from MODE 1. That is, after the overlap requirement has been met and indication has transitioned to the IRMs, maintaining overlap is not required (APRMs may be reading downscale once in MODE 2).

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channel(s) declared inoperable. Only those appropriate channels that are required in the current MODE or condition should be declared inoperable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.~~ INSERT 2

SR 3.3.1.1.7

This SR ensures that the total loop drive flow signals from the flow units used to vary the setpoint is appropriately compared to a valid core flow signal to verify the flow signal trip setpoint and, therefore, the APRM Function accurately reflects the required setpoint as a function of flow. If the flow unit signal is not within the appropriate flow limit, the affected APRMs that receive an input from the inoperable flow unit must be declared inoperable.

~~The Frequency of 31 days is based on engineering judgment, operating experience, and the reliability of this instrumentation.~~ INSERT 2

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. When the measured local flux profile is unavailable, the predicted LPRM reading may be used. This establishes the relative local flux profile for appropriate representative input to the APRM System. ~~The 1000 MWD/T Frequency is based on operating experience with LPRM sensitivity changes.~~ INSERT 2

SR 3.3.1.1.9 and SR 3.3.1.1.11

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. ~~The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 11.~~

~~The 24 month Frequency of SR 3.3.1.1.11 is based on the need to perform some of the surveillance procedures which satisfy this SR under~~

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~the conditions that apply during a plant outage and the potential for an unplanned transient if these particular procedures were performed with the reactor at power. Testing of Function 10 requires placing the mode switch in "Shutdown". Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.~~ INSERT 2

SR 3.3.1.1.9 for Function 3.3.1.1-1.2.d is modified by two Notes as identified in Table 3.3.1.1-1. 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. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the LTSP. Where a setpoint more conservative than the LTSP is used in the plant surveillance procedures (NTSP), 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 LTSP, then the channel shall be declared inoperable. The second Note also requires that LTSPs and the methodologies for calculating the as-left and the as-found tolerances be in the Technical Requirements Manual.

SR 3.3.1.1.10 and SR 3.3.1.1.12

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to the LTSP within the as-left tolerance to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. Physical inspection of the position switches is performed in conjunction with SR 3.3.1.1.12 for Functions 5, 7.b, and 8 to ensure that the switches are not corroded or otherwise degraded.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Note 1 of SR 3.3.1.1.10 and SR 3.3.1.1.12 states that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the ~~7 day~~ calorimetric calibration (SR 3.3.1.1.2) and the ~~1000 MWD/T~~ LPRM calibration against the TIPs (SR 3.3.1.1.8). Note 1 of SR 3.3.1.1.10 states that recirculation loop flow transmitters are excluded from CHANNEL CALIBRATION. This exclusion is based on calculation results and site-specific instrument setpoint drift data, which alternately supports ~~a 24 month calibration interval for the recirculation loop flow transmitters. As such, the flow transmitters are calibrated on a 24 month frequency as required by SR 3.3.1.1.12 for Function 2b.~~ the calibration interval specified in SR 3.3.1.1.12

INSERT 2

A second Note to SR 3.3.1.1.12 is provided that requires the APRM and IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

~~The Frequency of SR 3.3.1.1.10 is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.1.1.12 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~

Numerous SR 3.3.1.1.10 and 12 functions are modified by two Notes as identified in Table 3.3.1.1-1. 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. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the LTSP. Where a setpoint

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SURVEILLANCE REQUIREMENTS (continued)

more conservative than the LTSP is used in the plant surveillance procedures (NTSP), 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 LTSP, then the channel shall be declared inoperable. The second Note also requires that LTSPs and the methodologies for calculating the as-left and the as-found tolerances be in the Technical Requirements Manual.

SR 3.3.1.1.13

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), overlaps this Surveillance to provide complete testing of the assumed safety function.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if those particular procedures were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.~~ INSERT 2

SR 3.3.1.1.14

This SR ensures that scrams initiated from the Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 29.5% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed during an in-service calibration at THERMAL POWER ≥ 29.5% RTP to ensure that the calibration is valid.

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 29.5% RTP, then the affected Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are considered inoperable. Open main turbine bypass valve(s)

BASES

SURVEILLANCE REQUIREMENTS (continued)

can also affect these two functions. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

~~The Frequency of 24 months is based on engineering judgment and reliability of the components.~~ INSERT 2

SR 3.3.1.1.15

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. This test may be performed in one measurement or in overlapping segments, with verification that all components are tested. The RPS RESPONSE TIME acceptance criteria are included in Reference 13.

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.

~~The 24 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.~~ INSERT 2

REFERENCES

1. Regulatory Guide 1.105, "Setpoints for Safety-Related Instrumentation," Revision 3.
2. USAR, Section VII-2.
3. USAR, Chapter XIV.
4. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
5. USAR, Section VI-5.
6. 10 CFR 50.36(c)(2)(ii).
7. USAR, Section IV-4.9.
8. USAR, Section XIV-6.2.

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SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each SRM Applicable MODE or other specified conditions are found in the SRs column of Table 3.3.1.2-1.

SR 3.3.1.2.1 and SR 3.3.1.2.3

Performance of the CHANNEL CHECK 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 another channel. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or 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.

Agreement criteria are determined by the plant 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 instrument has drifted outside its limit.

~~The Frequency of once every 12 hours for SR 3.3.1.2.1 is based on operating experience that demonstrates channel failure is rare. While in MODES 3 and 4, reactivity changes are not expected; therefore, the 12 hour Frequency is relaxed to 24 hours for SR 3.3.1.2.3.~~ The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO. INSERT 2

SR 3.3.1.2.2

To provide adequate coverage of potential reactivity changes in the core when the fueled region encompasses more than one SRM, one SRM is required to be OPERABLE in the quadrant where CORE ALTERATIONS are being performed, and the other OPERABLE SRM must be in an adjacent quadrant containing fuel. Note 1 states that the SR is required to be met only during CORE ALTERATIONS. It is not required to be met at other times in MODE 5 since core reactivity changes are not occurring. This Surveillance consists of a review of plant logs to ensure that SRMs required to be OPERABLE for given CORE ALTERATIONS are, in fact, OPERABLE. In the event that only one SRM is required to be OPERABLE (when the fueled region encompasses only one SRM), per

BASES

SURVEILLANCE REQUIREMENTS (continued)

Table 3.3.1.2-1, footnote (b), only the a. portion of this SR is required. Note 2 clarifies that more than one of the three requirements can be met by the same OPERABLE SRM. ~~The 12 hour Frequency is based upon operating experience and supplements operational controls over refueling activities that include steps to ensure that the SRMs required by the LCO are in the proper quadrant.~~ INSERT 2

SR 3.3.1.2.4

This Surveillance consists of a verification of the SRM instrument readout to ensure that the SRM reading is greater than a specified minimum count rate with the detector full-in, which ensures that the detectors are indicating count rates indicative of neutron flux levels within the core. With few fuel assemblies loaded, the SRMs will not have a high enough count rate to satisfy the SR. Therefore, allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the minimum count rate.

To accomplish this, the SR is modified by a Note that states that the count rate is not required to be met on an SRM that has less than or equal to four fuel assemblies adjacent to the SRM and no other fuel assemblies are in the associated core quadrant. With four or less fuel assemblies loaded around each SRM and no other fuel assemblies in the associated core quadrant, even with a control rod withdrawn, the configuration will not be critical. This SR does not require determination of the noise ratio.

~~The Frequency is based upon channel redundancy and other information available in the control room, and ensures that the required channels are frequently monitored while core reactivity changes are occurring. When no reactivity changes are in progress, the Frequency is relaxed from 12 hours to 24 hours.~~ INSERT 2

SR 3.3.1.2.5 and SR 3.3.1.2.6

Performance of a CHANNEL FUNCTIONAL TEST demonstrates the associated channel will function properly. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. SR 3.3.1.2.5 is required in MODE 5 and ~~the 7 day~~

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~Frequency~~ ensures that the channels are OPERABLE while core reactivity changes could be in progress. ~~This Frequency is reasonable, based on operating experience and on other Surveillances (such as a CHANNEL CHECK), that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.~~ INSERT 2

SR 3.3.1.2.6 is required in MODE 2 with IRMs on Range 2 or below, and in MODES 3 and 4. ~~Since core reactivity changes do not normally take place in MODES 3 and 4, and core reactivity changes are due only to control rod movement in MODE 2, the Frequency has been extended from 7 days to 31 days. The 31 day Frequency is based on operating experience and on other Surveillances (such as CHANNEL CHECK) that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.~~ INSERT 2

Verification of the signal to noise ratio also ensures that the detectors are inserted to an acceptable operating level. In a fully withdrawn condition, the detectors are sufficiently removed from the fueled region of the core to essentially eliminate neutrons from reaching the detector. Any count rate obtained while the detectors are fully withdrawn is assumed to be "noise" only. An alternative to fully withdrawing the detector is to configure the assembly cabling such that only the noise signal is observed.

The Note to SR 3.3.1.2.6 allows the Surveillance to be delayed until entry into the specified condition of the Applicability (THERMAL POWER decreased to IRM Range 2 or below). The SR must be performed within 12 hours after IRMs are on Range 2 or below. The allowance to enter the Applicability with the ~~31 day~~ Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

SR 3.3.1.2.7

Performance of a CHANNEL CALIBRATION ~~at a Frequency of 24 months~~ verifies the performance of the SRM detectors and associated circuitry. The Frequency considers the plant conditions required to perform the test, the ease of performing the test, and the likelihood of a change in the system or component status. The neutron detectors are excluded from the CHANNEL CALIBRATION (Note 1) because they cannot readily be

BASES

SURVEILLANCE REQUIREMENTS (continued)

adjusted. The detectors are fission chambers that are designed to have a relatively constant sensitivity over the range and with an accuracy specified for a fixed useful life.

Note 2 to the Surveillance allows the Surveillance to be delayed until entry into the specified condition of the Applicability. The SR must be performed in MODE 2 within 12 hours of entering MODE 2 with IRMs on Range 2 or below. The allowance to enter the Applicability with the ~~24-month~~ Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology.

REFERENCES None.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.1 from previous page (not included)

Technical Specifications and non-Technical Specifications tests ~~at least once per refueling interval with applicable extensions~~.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. ~~The Frequency of 92 days is based on reliability analyses (Ref. 11).~~ INSERT 2

SR 3.3.2.1.2 and SR 3.3.2.1.3

A CHANNEL FUNCTIONAL TEST is performed for the RWM to ensure that the system will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST for the RWM includes performing the RWM computer on line diagnostic test satisfactorily, attempting to withdraw a control rod not in compliance with the prescribed sequence and verifying a control rod block occurs. For SR 3.3.2.1.2, the CHANNEL FUNCTIONAL TEST also includes attempting to select a control rod not in compliance with the prescribed sequence and verifying a selection error occurs. As noted in the SRs, SR 3.3.2.1.2 is not required to be performed until 1 hour after any control rod is withdrawn in MODE 2. As noted, SR 3.3.2.1.3 is not required to be performed until 1 hour after THERMAL POWER is ≤ 9.85% RTP in MODE 1. This allows entry into MODE 2 for SR 3.3.2.1.2, and entry into MODE 1 when THERMAL POWER is ≤ 9.85% RTP for SR 3.3.2.1.3, to perform the required Surveillance if the ~~92 day~~ Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. ~~The Frequencies are based on reliability analysis (Ref. 11).~~ INSERT 2

SR 3.3.2.1.4

The RBM power range setpoints control the enforcement of the appropriate upscale trips over the proper core thermal power range of the Applicability Notes (a), (b), (c), (d), and (e) of ITS Table 3.3.2.1-1. The RBM Upscale Trip Function setpoints are automatically varied as a function of power. Three Allowable Values are specified in the COLR as denoted in Table 3.3.2.1-1, each within a specific power range. The power at which the control rod block Allowable Values automatically

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SURVEILLANCE REQUIREMENTS (continued)

change are based on the reference APRM signal's input to each RBM channel. Below the minimum power setpoint of 27.5% RTP or when a peripheral control rod is selected, the RBM is automatically bypassed. These power Allowable Values must be verified periodically by determining that the power level setpoints are less than or equal to the specified values. If any power range setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the power range channel can be placed in the conservative condition (i.e., enabling the proper RBM setpoint). If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.8. ~~The 184 day Frequency is based on the actual trip setpoint methodology utilized for these channels.~~

INSERT 2

SR 3.3.2.1.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

As noted, neutron detectors are excluded from the CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.8.

~~The Frequency is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~

INSERT 2

SR 3.3.2.1.5 for Functions 3.3.2.1-1.1.a, 3.3.2.1-1.1.b and 3.3.2.1-1.1.c is modified by two Notes as identified in Table 3.3.2.1-1. 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. For channels determined to be

BASES

SURVEILLANCE REQUIREMENTS (continued)

OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the LTSP. Where a setpoint more conservative than the LTSP is used in the plant surveillance procedures (NTSP), 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 LTSP, then the channel shall be declared inoperable. The second Note also requires that LTSPs and the methodologies for calculating the as-left and the as-found tolerances be in the Technical Requirements Manual.

SR 3.3.2.1.6

The RWM is automatically bypassed when power is above a specified value. The power level is determined from feedwater flow and steam flow signals. The setpoint where the automatic bypass feature is unbypassed must be verified periodically to be > 9.85% RTP. If the RWM low power setpoint is nonconservative, then the RWM is considered inoperable. Alternately, the low power setpoint channel can be placed in the conservative condition (nonbypass). If placed in the nonbypassed condition, the SR is met and the RWM is not considered inoperable. ~~The Frequency is based on the trip setpoint methodology utilized for the low power setpoint channel.~~ INSERT 2

SR 3.3.2.1.7

A CHANNEL FUNCTIONAL TEST is performed for the Reactor Mode Switch-Shutdown Position Function to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST for the Reactor Mode Switch-Shutdown Position Function is performed by attempting to withdraw any control rod with the reactor mode switch in the shutdown position and verifying a control rod block occurs.

BASES

SURVEILLANCE REQUIREMENTS (continued)

As noted in the SR, the Surveillance is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads, or movable links. This allows entry into MODES 3 and 4 if the ~~24 month~~ Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if these particular procedures were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.~~ INSERT 2

SR 3.3.2.1.8

The RWM will only enforce the proper control rod sequence if the rod sequence is properly input into the RWM computer. This SR ensures that the proper sequence is loaded into the RWM so that it can perform its intended function. The Surveillance is performed once prior to declaring RWM OPERABLE following loading of sequence into RWM, since this is when rod sequence input errors are possible.

REFERENCES

1. Regulatory Guide 1.105, "Setpoints for Safety-Related Instrumentation," Revision 3.
2. USAR, Section VII-7.
3. USAR, Section VII-16.3.3.
4. NEDC-31892P, "Extended Load Line Limit and ARTS Improvement Program Analyses for Cooper Nuclear Station," Rev. 1, May 1991.
5. 10 CFR 50.36(c)(2)(ii).
6. USAR, Section XIV-6.2.
7. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

BASES

REFERENCES

8. NEDO 33091, Revision 2, "Improved BPWS Control Rod Insertion Process," April 2003.

9. NRC SER, "Acceptance of Referencing of Licensing Topical Report NEDE-24011-P-A," "General Electric Standard Application for Reactor Fuel, Revision 8, Amendment 17," December 27, 2987.

10. GENE-770-06-1, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

~~11. NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988.~~

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.2.1

Performance of the CHANNEL CHECK ~~once every 24 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 instrument channels could be an indication of excessive instrument drift in one of the channels, or 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.

Agreement criteria are determined by the plant 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 instrument has drifted outside its limits.

~~The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with the channels required by the LCO.~~ INSERT 2

SR 3.3.2.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology.

~~The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~ INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.2.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the feedwater and main turbine valves is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a valve is incapable of operating, the associated instrumentation would also be inoperable. ~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if those particular procedures were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.~~ INSERT 2

REFERENCES

1. USAR, Section XIV-5.8.1.
2. 10 CFR 50.36(c)(2)(ii).
3. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

BASES

ACTIONS (continued)

E.1

For the majority of Functions in Table 3.3.3.1-1, if any Required Action and associated Completion Time of Condition C is not met, the plant must be brought to a MODE in which the LCO not apply. To achieve this status, the plant must be brought to at least MODE 3 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.

F.1

Since alternate means of monitoring primary containment area radiation have been developed and tested, the Required Action is not to shut down the plant, but rather to follow the directions of Specification 5.6.6. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1.1

Performance of the CHANNEL CHECK ~~once every 31 days~~ ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel against 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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant instruments located throughout the plant. The CHANNEL CHECK does not apply to the primary containment H_2 and O_2 analyzer that is in a normal standby configuration.

Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including isolation,

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 of 31 days is based upon plant operating experience, with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 31 day interval is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of those displays associated with the channels required by the LCO.~~ INSERT 2

SR 3.3.3.1.2 and SR 3.3.3.1.3

These SRs require a CHANNEL CALIBRATION to be performed. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies the channel responds to measured parameter with the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology. For the Primary Containment Gross Radiation Monitors, the CHANNEL CALIBRATION consists of an electronic calibration of the channel, excluding the detector, for range decades ≥ 10 R/hour and a one point calibration check of the detector with an installed or portable gamma source for range decades < 10 R/hour. For the PCIV Position Function, the CHANNEL CALIBRATION consists of verifying the remote indication conforms to actual value position.

~~The 92 day Frequency for CHANNEL CALIBRATION of the Primary Containment Hydrogen and Oxygen Analyzers is based on vendor recommendations. The 24 month Frequency for CHANNEL CALIBRATION of all other PAM instrumentation of Table 3.3.3.1-1 is based on operating experience and consistency with the CNS refueling cycles.~~ INSERT 2

REFERENCES

1. Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Revision 3," May 1985.

2. Letter from G. A. Trevors (NPPD) to U.S. NRC dated April 12, 1990, "NUREG-0737, Supplement 1-Regulatory Guide 1.97 Response, Revision IX."

BASES

ACTIONS

A Note has been provided to modify the ACTIONS related to Alternate Shutdown System Functions. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable Alternate Shutdown System Functions provide appropriate compensatory measures for separate Functions. As such, a Note has been provided that allows separate Condition entry for each inoperable Alternate Shutdown System Function.

A.1

Condition A addresses the situation where one or more required Functions of the Alternate Shutdown System is inoperable. This includes any Function listed in Table B 3.3.3.2-1.

The Required Action is to restore the Function (both divisions, if applicable) to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1

If the Required Action and associated Completion Time of Condition A 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 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.1

Performance of the CHANNEL CHECK ~~once every 31 days~~ 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

instrument channels could be an indication of excessive instrument drift in one of the channels or 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.

Agreement criteria are determined by the plant 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. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

~~The Frequency is based upon plant operating experience that demonstrates channel failure is rare.~~ INSERT 2

SR 3.3.3.2.2

SR 3.3.3.2.2 verifies each required Alternate Shutdown System transfer switch and control circuit performs the intended function. This verification is performed from the alternate shutdown panel and locally, as appropriate. Operation of the equipment from the alternate shutdown panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be placed and maintained in a safe shutdown condition from the alternate shutdown panel and the local control stations. However, this Surveillance is not required to be performed only during a plant outage. ~~Operating experience demonstrates that Alternate Shutdown System control channels usually pass the Surveillance when performed at the 24 month Frequency.~~ INSERT 2

SR 3.3.3.2.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies the channel responds to measured parameter values with the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology.

~~The 24 month Frequency is based upon operating experience and consistency with the typical industry refueling cycle.~~ INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.1 from previous page (not included)

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~~.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

~~The Frequency of 92 days is based on the reliability analysis of Reference 3.~~ INSERT 2

SR 3.3.4.1.2

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology.

~~The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~ INSERT 2

SR 3.3.4.1.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. For the Reactor Vessel Water Level-Low Low (Level 2) logic, this shall include the nominal 9 second time delay of the RRMG field breaker trip. The system functional test of the RRMG field breakers is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if an RRMG field breaker is incapable of operating, the associated instrument channel(s) would be inoperable.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if those particular procedures were performed with the reactor at power.~~

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.~~

INSERT 2

REFERENCES

1. USAR, Section VII-9.5.4.2.

2. 10 CFR 50.36(c)(2)(ii).

3. GENE-770-06-1, "Bases for Changes To Surveillance Test Intervals and Allowed Out-of-Service Times For Selected Instrumentation Technical Specifications," February 1991.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK guarantees that undetected outright channel failure is limited ~~to 12 hours~~; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant 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 instrument has drifted outside its limit.

~~The Frequency is based upon 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 channels required by the LCO.

INSERT 2

SR 3.3.5.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests ~~at least once per refueling interval with applicable extensions~~.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

~~The Frequency of 92 days is based on the reliability analyses of Reference 9.~~

INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.3 and SR 3.3.5.1.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

~~The Frequency of SR 3.3.5.1.3 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~

~~The Frequency of SR 3.3.5.1.4 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~ INSERT 2

SR 3.3.5.1.4 for selected functions is modified by two Notes as identified in Table 3.3.5.1-1. 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. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the LTSP. Where a setpoint more conservative than the LTSP is used in the plant surveillance procedures (NTSP), 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 LTSP, then the channel shall be declared inoperable. The second Note also requires that LTSPs and the methodologies for calculating the as-left and the as-found tolerances be in the Technical Requirements Manual.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic and simulated automatic actuation for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to complete testing of the assumed safety function.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if these particular procedures were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.~~

INSERT 2

REFERENCES

1. Regulatory Guide 1.105, "Setpoints for Safety-Related Instrumentation," Revision 3.

2. Amendment No. 7 to Facility License No DPR-46 for the Cooper Nuclear Station, February 6, 1975.

3. Cooper Nuclear Station Design Change 94-332, December 1994.

4. NEDC 97-023, "HPCI Minimum Flow Line Analysis."

5. 10 CFR 50.36(c)(2)(ii).

6. USAR, Section V-2.4.

7. USAR, Section VI-5.0.

8. USAR, Chapter XIV.

9. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Function 2; and (b) for up to 6 hours for Functions 1 and 3, provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RCIC will initiate when necessary.

SR 3.3.5.2.1

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 parameter on other similar channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or 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.

Agreement criteria are determined by the plant 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 instrument has drifted outside its limit.

~~The Frequency is based upon 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 channels required by the LCO.

INSERT 2

SR 3.3.5.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be

BASES

SURVEILLANCE REQUIREMENTS (continued)

performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests ~~at least once per refueling interval with applicable extensions.~~

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

~~The Frequency of 92 days is based on the reliability analysis of Reference 3.~~ INSERT 2

SR 3.3.5.2.3 and SR 3.3.5.2.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

~~The Frequency of SR 3.3.5.2.3 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~ INSERT 2

~~The Frequency of SR 3.3.5.2.4 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~

SR 3.3.5.2.3 and SR 3.3.5.2.4 are modified by two Notes as identified in Table 3.3.5.2-1. 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 safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the

BASES

SURVEILLANCE REQUIREMENTS (continued)

channel be within the as-left tolerance of the LTSP. Where a setpoint more conservative than the LTSP is used in the plant surveillance procedures (NTSP), 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 LTSP, then the channel shall be declared inoperable. The second Note also requires that LTSPs and the methodologies for calculating the as-left and the as-found tolerances be in the Technical Requirements Manual.

SR 3.3.5.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.3 overlaps this Surveillance to provide complete testing of the safety function. ~~Simulated automatic actuation is performed each operating cycle.~~

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if these particular procedures were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.~~ INSERT 2

REFERENCES

1. Regulatory Guide 1.105, "Setpoints for Safety-Related Instrumentation," Revision 3.
2. 10 CFR 50.36(c)(2)(ii).
3. GENE-770-06-2, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

BASES

ACTIONS (continued)

the penetration flow path can be isolated). Actions must continue until the channel is restored to OPERABLE status or the RHR Shutdown Cooling System is isolated.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Primary Containment Isolation instrumentation Function are found in the SRs column of Table 3.3.6.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 10 and 11) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the PCIVs will isolate the penetration flow path(s) when necessary.

SR 3.3.6.1.1

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 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.

Agreement criteria are determined by the plant 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 instrument has drifted outside its limit.

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~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 channels required by the LCO.

INSERT 2

SR 3.3.6.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests ~~at least once per refueling interval with applicable extensions~~.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

~~The 92 day Frequency of SR 3.3.6.1.2 is based on the reliability analysis described in References 10 and 11.~~

INSERT 2

SR 3.3.6.1.3, SR 3.3.6.1.4 and SR 3.3.6.1.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. SR 3.3.6.1.5, however, is only a calibration of the radiation detectors using a standard radiation source.

As noted for SR 3.3.6.1.4, the main steam line radiation detectors (Function 2.d) are excluded from CHANNEL CALIBRATION due to ALARA reasons (when the plant is operating, the radiation detectors are generally in a high radiation area; the steam tunnel). This exclusion is acceptable because the radiation detectors are passive devices, with minimal drift. The radiation detectors are calibrated in accordance with SR 3.3.6.1.5 ~~on a 24 month Frequency~~ using a standard current source

BASES

SURVEILLANCE REQUIREMENTS (continued)

and radiation source. The CHANNEL CALIBRATION of the remaining portions of the channel (SR 3.3.6.1.4) are performed using a standard current source.

~~The Frequency of SR 3.3.6.1.3 is based on the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.6.1.4 and SR 3.3.6.1.5 is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~ INSERT 2

SR 3.3.6.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on PCIVs in LCO 3.6.1.3 overlaps this Surveillance to provide complete testing of the assumed safety function. ~~Simulated automatic actuation is performed each operating cycle. The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if these particular procedures were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.~~ INSERT 2

REFERENCES

1. USAR, Table V-2-2.
2. USAR, Chapter XIV.
3. 10 CFR 50.36(c)(2)(ii).
4. USAR, Section XIV-6.3.
5. USAR, Section XIV-5.4.1.
6. USAR, Section XIV-6.5.
7. USAR, Section XIV-6.7.1.
8. NEDO-31466, "Technical Specification Screening Criteria Application and Risk Assessment," November 1987.

BASES

SURVEILLANCE REQUIREMENTS (continued)

isolate the associated penetration flow paths and that the SGT System will initiate when necessary.

SR 3.3.6.2.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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.

Agreement criteria are determined by the plant 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 instrument 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 channel status during normal operational use of the displays associated with channels required by the LCO.

INSERT 2

SR 3.3.6.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests ~~at least once per refueling interval with applicable extensions.~~

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~The Frequency of 92 days is based on the reliability analysis of References 5 and 6.~~ INSERT 2

SR 3.3.6.2.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

~~The Frequency of SR 3.3.6.2.3 is based on the assumption of a 24 month calibration interval, respectively, in the determination of the magnitude of equipment drift in the setpoint analysis.~~ INSERT 2

SR 3.3.6.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on SCIVs and the SGT System in LCO 3.6.4.2 and LCO 3.6.4.3, respectively, overlaps this Surveillance to provide complete testing of the assumed safety function.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if those particular procedures were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.~~ INSERT 2

REFERENCES

1. USAR, Section V-3.0.
2. USAR, Chapter XIV.
3. 10 CFR 50.36(c)(2)(ii).
4. USAR, Sections XIV-6.3 and XIV-6.4.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the LLS valves will initiate when necessary.

SR 3.3.6.3.1, SR 3.3.6.3.2, and SR 3.3.6.3.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests ~~at least once per refueling interval with applicable extensions.~~ Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

INSERT 2

~~The 92 day Frequency is based on the reliability analysis of Reference 3.~~

A portion of the SRV discharge line pressure switch instrument channels are located inside the primary containment. The Note for SR 3.3.6.3.2, "Only required to be performed prior to entering MODE 2 during each scheduled outage > 72 hours when entry is made into primary containment," is based on the location of these instruments and ALARA considerations.

SR 3.3.6.3.4

CHANNEL CALIBRATION is a complete check of the instrument loop and sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

~~The Frequency of once every 24 months for SR 3.3.6.3.4 is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~ INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.3.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specified channel. The system functional testing performed in LCO 3.4.3, "Safety/Relief Valves (SRVs) and Safety Valves (SVs)" and LCO 3.6.1.6, "Low-Low Set (LLS) Safety/Relief Valves (SRVs)," for SRVs overlaps this test to provide complete testing of the assumed safety function.

~~The Frequency of once every 24 months for SR 3.3.6.3.5 is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if those particular procedures were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24-month Frequency.~~ INSERT 2

REFERENCES

1. USAR, Section IV-4.5.2.
2. 10 CFR 50.36(c)(2)(ii).
3. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.1.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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.

Agreement criteria are determined by the plant 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 instrument has drifted outside its limit.

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

INSERT 2

SR 3.3.7.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests ~~at least once per refueling interval with applicable extensions~~.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

~~The Frequency of 92 days is based on the reliability analyses of References 5, 6, and 7.~~

INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

~~The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~ INSERT 2

SR 3.3.7.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.7.4, "Control Room Emergency Filter (CREF) System," overlaps this Surveillance to provide complete testing of the assumed safety function.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if these particular procedures were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.~~ INSERT 2

REFERENCES

1. USAR, Section X-10.4.

2. USAR, Section XIV-6.3.

3. USAR, Section XIV-6.4.

4. 10 CFR 50.36(c)(2)(ii).

5. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

BASES

ACTIONS (continued)

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

B.1

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated DG(s) is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs (Note 1), the SRs for each LOP instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

The Surveillances are further modified by a Note (Note 2) to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains initiation capability. Initiation capability is maintained provided that the following can be initiated by the Function for one DG or emergency bus as applicable (if part of that Function): DG start, disconnect from offsite power source, DG output breaker closure, and load shed. Upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

SR 3.3.8.1.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests ~~at least once per refueling interval with~~

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.1 from previous page (not included)

~~applicable extensions.~~ Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

~~The Frequency of 31 days is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 31 day interval is a rare event.~~ INSERT 2

SR 3.3.8.1.2

A CHANNEL CALIBRATION is a complete check of the relay circuitry and associated time delay relays. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

~~The Frequency is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~ INSERT 2

SR 3.3.8.1.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed in LCO 3.8.1 and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety functions.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if these particular procedures were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.~~ INSERT 2

BASES

ACTIONS (continued)

D.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 5, with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Required Action D.1 results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required. Action must continue until the Required Action is completed.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

~~The Frequency is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.~~ INSERT 2

SR 3.3.8.2.2

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the logic of the system will automatically trip open the associated power monitoring assembly. The system functional test shall include actuation of the protective relays, tripping logic, and output circuit breakers. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if these particular procedures were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.~~

INSERT 2

REFERENCES

1. USAR, Section VII-2.3.
2. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIRMENTS (continued)

SR 3.4.1.1 from previous page (not included)

The mismatch is measured in terms of percent of rated core flow. If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered inoperable. The SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be performed within 24 hours after both loops are in operation. ~~The 24 hour Frequency is consistent with the Surveillance Frequency for jet pump OPERABILITY verification and has been shown by operating experience to be adequate to detect off normal loop flows in a timely manner.~~ INSERT 2

SR 3.4.1.2

This SR ensures the core flow, as a function of core THERMAL POWER, is within the appropriate limits to prevent uncontrolled thermal hydraulic oscillations. At low flows and high power levels the reactor exhibits increased susceptibility to thermal hydraulic instability. The power/flow map is based on the guidance provided in Reference 5. ~~The 24 hour Frequency is based on operating experience and the operator's inherent knowledge of reactor status, including significant changes in core THERMAL POWER and flow.~~ INSERT 2

REFERENCES

1. NEDE-24011-P-A (Revision specified in the COLR).

2. USAR, Section IV-3.6.

3. NEDE-24258, "Cooper Nuclear Station Single-Loop Operation," May, 1980.

4. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

relationship may indicate a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the recirculation pump flow and jet pump loop flow versus pump speed relationship must be verified.

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The jet pump diffuser to lower plenum differential pressure pattern is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 3). Normal flow ranges and established jet pump differential pressure patterns are established by plotting historical data as discussed in Reference 3.

~~The 24 hour Frequency has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop OPERABILITY verification.~~ INSERT 2

This SR is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

Note 2 allows this SR not to be performed until 24 hours after THERMAL POWER exceeds 25% of RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data. The 24 hours is an acceptable time to establish conditions appropriate to perform this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.3.2

A manual actuation of each SRV (until the main turbine bypass valves have closed to compensate for SRV opening) is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can also be demonstrated by the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or by any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure and steam flow when the SRVs divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this test. Adequate pressure at which this test is to be performed is ≥ 500 psig, consistent with the recommendations of the vendor. Adequate steam flow is represented by turbine bypass valves at least 30% open, or total steam flow ≥ 10^6 lb/hr. Plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME Code requirements, prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure and steam flow are reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If a valve fails to actuate due only to the failure of the solenoid but is capable of opening on overpressure, the safety function of the SRV is not considered inoperable.

~~The 24 month Frequency was developed based on the SRV tests required by the ASME Code for Operation and Maintenance of Nuclear Power Plants (Ref. 6). Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

BASES

ACTIONS

C.1 and C.2 (continued)

based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

The RCS LEAKAGE is monitored by a variety of instruments designed to provide alarms when LEAKAGE is indicated and to quantify the various types of LEAKAGE. Leakage detection instrumentation is discussed in more detail in the Bases for LCO 3.4.5, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates; however, any method may be used to quantify LEAKAGE within the guidelines of Reference 7. ~~In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying LEAKAGE and for tracking required trends (Ref. 8).~~ INSERT 2

REFERENCES

1. 10 CFR 50.2.

2. 10 CFR 50.55a(c).

3. USAR, Section IV-10.

4 GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.

5. NUREG-76/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping in Boiling Water Reactors," October 1975.

6. 10 CFR 50.36(c)(2)(ii).

7. Regulatory Guide 1.45, May 1973.

~~8. Generic Letter 88-01, Supplement 1, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," February 1992.~~

BASES

ACTIONS (continued)

restoration recognizes that at least one other form of leakage detection is available.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B cannot be 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 12 hours and MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the actions in an orderly manner and without challenging plant systems.

D.1

With all required monitors inoperable, no required automatic means of monitoring LEAKAGE are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR is for the performance of a CHANNEL CHECK of the required drywell atmospheric monitoring system. 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.~~ INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.5.2

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests ~~at least once per refueling interval with applicable extensions. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.~~ INSERT 2

SR 3.4.5.3

This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string. ~~The Frequency is 92 days and operating experience has proven this Frequency is acceptable.~~ INSERT 2

REFERENCES

1. USAR, Section IV-10.2.
2. Regulatory Guide 1.45, May 1973.
3. USAR, Section IV-10.3.
4. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968.
5. NUREG-75/067, "Investigation and Evaluation of Cracking in Austetic Stainless Steel Piping of Boiling Water Reactors," October 1975.
6. USAR, Section IV-10.3.2.
7. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 12 hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for placing the unit in MODES 3 and 4 are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This Surveillance is performed to ensure iodine remains within limit during normal operation. ~~The 7 day Frequency is adequate to trend changes in the iodine activity level.~~ INSERT 2

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the level of fission products generated in other MODES is much less.

REFERENCES

1. 10 CFR 100.11, 1973.
2. USAR, Section XIV-8.1.
3. USAR, Section XIV-6.5.
4. 10 CFR 50, Appendix A, GDC 19.
5. 10 CFR 50.36(c)(2)(ii).
6. 10 CFR 50.67.

BASES

ACTIONS

B.1, B.2, and B.3 (continued)

circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. ~~The frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.~~ INSERT 2

This Surveillance is modified by a Note allowing sufficient time to align the RHR System for shutdown cooling operation after clearing the pressure interlock that isolates the system, or for placing a recirculation pump in operation. The Note takes exception to the requirements of the Surveillance being met (i.e., forced coolant circulation is not required for this initial 2 hour period), which also allows entry into the Applicability of this Specification in accordance with SR 3.0.4 since the Surveillance will not be "not met" at the time of entry into the Applicability.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

periodically monitored to ensure proper functioning of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. ~~The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.~~ INSERT 2

REFERENCES

1. USAR, Appendix G.
2. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS

B.1 and B.2 (continued)

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.

C.1 and C.2

Operation outside the P/T limits in other than MODES 1, 2, and 3 (including defueled conditions) must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses. The Required Action must be initiated without delay and continued until the limits are restored.

Besides restoring the P/T limit parameters to within limits, an evaluation is required to determine if RCS operation is allowed. This evaluation must verify that the RCPB integrity is acceptable and must be completed before approaching criticality or heating up to > 212°F. Several methods may be used, including comparison with pre-analyzed transients, new 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 beltline.

Condition C is modified by a Note requiring Required Action C.2 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 reactor pressure vessel integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

Verification that operation is within RCS pressure, RCS temperature, and RCS heatup and cooldown rate limits by monitoring the bottom head drain, recirculation loop temperatures, and RPV metal temperatures (Beltline, Bottom Head, and Upper Vessel) is required ~~every 30 minutes~~ when RCS pressure and temperature conditions are undergoing planned changes. ~~This Frequency is considered~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~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 permits a reasonable time for assessment and correction of minor deviations.~~ INSERT 2

Surveillance for heatup, cooldown, or inservice leakage and hydrostatic testing may be discontinued when the difference between any two readings taken over a 45 minute period is less than 50°F.

This SR has been modified with a Note that requires this Surveillance to be performed only during system heatup and cooldown operations and inservice leakage and hydrostatic testing. During RCS heatup and cooldown operation (i.e., not critical and not performing inservice leak or hydrostatic testing) verify RCS pressure and temperature are within the applicable limits specified in Figure 3.4.9-1. During RCS inservice leak and hydrostatic testing verify RCS pressure and temperature are within the applicable limits specified in Figure 3.4.9-2.

SR 3.4.9.2

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS pressure and temperature must be verified within the appropriate limits before withdrawing control rods that will make the reactor critical.

Performing the Surveillance within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal.

SR 3.4.9.3 and SR 3.4.9.4

Differential temperatures within the specified limits ensure that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits ensures that the assumptions of the analysis for the startup of an idle recirculation loop (Ref. 9) are satisfied.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the idle pump start.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.9.3 is to compare the bottom head drain temperature to the RPV steam dome saturation temperature.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.9.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.9.3 and SR 3.4.9.4 have been modified by a Note that requires the Surveillance to be performed only in MODES 1, 2, 3, and 4 during a recirculation pump startup since this is when the stresses occur. In MODE 5, the overall stress on limiting components is lower. Therefore, ΔT limits are not required.

SR 3.4.9.5, SR 3.4.9.6, and SR 3.4.9.7

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

The flange temperatures must be verified to be above the limits ~~within 30 minutes~~ before and while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with RCS temperature ≤ 80°F, ~~30 minute~~ checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature ≤ 90°F, monitoring of the flange temperature is required ~~every 12 hours~~ to ensure the temperature is within the specified limits.

INSERT 2

~~The 30 minute Frequency reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The 12 hour Frequency is reasonable based on the rate of temperature change possible at these temperatures.~~

SR 3.4.9.5 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.9.6 is modified by a Note that requires the Surveillance to be

BASES

APPLICABILITY (continued)

MODES, the reactor may be generating significant steam and events that may challenge the overpressure limits are possible.

In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.

ACTIONS

A.1

With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident occurring while pressure is greater than the limit is minimized.

B.1

If the reactor steam dome pressure cannot be restored to within the limit 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 at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

Verification that reactor steam dome pressure is ≤ 1020 psig ensures that the initial conditions of the vessel overpressure protection analysis are met. ~~Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.~~ INSERT 2

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

If any Required Action and associated Completion Time of Condition C, D, E, or F is not met, or if two or more ADS valves are inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig 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.

H.1

When multiple ECCS subsystems are inoperable, as stated in Condition H, the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCI System, CS System, and LPCI subsystems full of water ensures that the ECCS will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method is to vent from the system high point until water flow is observed. ~~The 31 day Frequency is based on the gradual nature of void buildup in the ECCS piping, the procedural controls governing system operation, and operating experience.~~ INSERT 2

SR 3.5.1.2

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 applies only to valves affecting the direct flow path. This SR excludes valves that, if mispositioned, would not affect system or subsystem

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 (continued)

OPERABILITY. Also, 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 initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the HPCI System, this SR also includes the steam flow path for the turbine and the flow controller position.

~~The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve position would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.~~ INSERT 2

In Mode 3 with reactor steam dome pressure less than the actual shutdown cooling permissive pressure, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, this SR is modified by a Note that allows LPCI subsystems to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. At the low pressures and decay heat loads associated with operation in MODE 3 with reactor steam dome pressure less than the shutdown cooling permissive pressure, a reduced complement of low pressure ECCS subsystems should provide the required cooling, thereby allowing operation of RHR shutdown cooling, when necessary.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.3

Verification ~~every 31 days~~ that ADS pneumatic supply header pressure is ≥ 88 psig ensures adequate pneumatic pressure for reliable ADS operation. Prior to startup, the normal pneumatic supply is from instrument air, and after startup, the normal supply is from instrument nitrogen. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator, at least two valve actuations can occur with the drywell at 70% of design pressure (Ref. 12). The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥ 88 psig is provided by the ADS instrument pneumatic supply. ~~The 31 day Frequency takes into consideration administrative controls over operation of the pneumatic system and alarms for low pneumatic pressure.~~

INSERT 2

SR 3.5.1.4

Verification ~~every 31 days~~ that the RHR System cross tie shutoff valve is closed ensures that each LPCI subsystem remains independent and a failure of the flow path in one subsystem will not affect the flow path of the other LPCI subsystem. If the RHR System cross tie shutoff valve is open, both LPCI subsystems must be considered inoperable. ~~The 31 day Frequency has been found acceptable, considering that the valve is under strict administrative controls that will ensure the valve continues to remain closed.~~

INSERT 2

SR 3.5.1.5

Cycling the recirculation pump discharge valves through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will close when required. Upon initiation of an automatic LPCI subsystem injection signal, these valves are required to be closed to ensure full LPCI subsystem flow injection in the reactor via the recirculation jet pumps. De-energizing the valve in the closed position will also ensure the proper flow path for

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

the LPCI subsystem. Acceptable methods of de-energizing the valve include de-energizing breaker control power, racking out the breaker or removing the breaker.

The specified Frequency is once during reactor startup before THERMAL POWER is > 25% RTP. However, this SR is modified by a Note that states the Surveillance is only required to be performed if the last performance was more than 31 days ago. Therefore, implementation of this Note requires this test to be performed during reactor startup before exceeding 25% RTP. Verification during reactor startup prior to reaching > 25% RTP is an exception to the normal Inservice Testing Program generic valve cycling Frequency ~~of 92 days~~, but is considered acceptable due to the demonstrated reliability of these valves. If the valve is inoperable and in the open position, the associated LPCI subsystem must be declared inoperable.

SR 3.5.1.6, SR 3.5.1.7, and SR 3.5.1.8

The performance requirements of the low pressure ECCS pumps are determined through application of the 10 CFR 50, Appendix K criteria (Ref. 7). This periodic Surveillance is performed (in accordance with the ASME Code for Operation and Maintenance of Nuclear Power Plants requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The low pressure ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of Reference 8. The pump flow rates are verified against a system head equivalent to the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during a LOCA.

The flow tests for the HPCI System are performed at two different pressure ranges such that system capability to provide rated flow against a system head corresponding to reactor pressure is tested at both the higher and lower operating ranges of the system. The required system head

BASES

SURVEILLANCE REQUIREMENTS (continued)

should overcome the RPV pressure and associated discharge line losses. Adequate reactor pressure must be available to perform these tests. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these tests. Adequate reactor steam pressure must be ≥ 920 psig to perform SR 3.5.1.7 and ≥ 145 psig to perform SR 3.5.1.8. Adequate steam flow is represented by turbine bypass valves at least 30% open, or total steam flow ≥ 10^6 lb/hr. Reactor startup is allowed prior to performing the low pressure Surveillance test because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance test is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that HPCI is inoperable.

Therefore, SR 3.5.1.7 and SR 3.5.1.8 are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for the flow tests after required pressure and flow are reached are sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SRs. For SR 3.5.1.8, while adequate pressure can be reached prior to the required Applicability for HPCI, the 12 hour allowance of the Note would not apply until entering the Applicability (>150 psig) with adequate steam flow.

The Frequency for SR 3.5.1.6 ~~and SR 3.5.1.7~~ is in accordance with the Inservice Testing Program requirements. ~~The 24 month Frequency for SR 3.5.1.8 is based on the need to perform the Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~

The Frequency for SR 3.5.1.7 and SR 3.5.1.8 is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.9

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCI, CS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. This SR also ensures that the HPCI System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the ECSTs to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if those particular procedures were performed with the reactor at power.~~

INSERT 2

~~Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~

This SR is modified by Note 1 that says for HPCI only the Surveillance is not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test. The time allowed for this test after required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. Adequate reactor pressure must be available to perform this test. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Thus, sufficient time is allowed after adequate pressure and flow are achieved to perform this test. Adequate reactor steam pressure is > 145 psig. Adequate steam flow is represented by turbine bypass valves at least

BASES

SURVEILLANCE REQUIREMENTS (continued)

30% open, or a total steam flow of 10^6 lb/hr. Reactor startup is allowed prior to performing this test because the reactor pressure is low and the time allowed to satisfactorily perform the test is short. For SR 3.5.1.9, while adequate pressure can be reached prior to the required Applicability for HPCI, the 12 hour allowance of the Note would not apply until entering the Applicability (>150 psig) with adequate steam flow.

This SR is modified by Note 2 that excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

SR 3.5.1.10

The ADS designated SRVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to demonstrate that the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components. SR 3.5.1.11 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if those particular procedures were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

This SR is modified by a Note that excludes valve actuation since the valves are individually tested in accordance with SR 3.5.1.11. This also prevents an RPV pressure blowdown.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.11

A manual actuation of each ADS valve is performed to verify that the valve and solenoid are functioning properly and that no blockage exists in the SRV discharge lines. This is demonstrated by the response of the turbine control or bypass valve or by a change in the measured flow or by any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the ADS valves divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this SR. Adequate pressure at which this SR is to be performed is ≥ 500 psig (consistent with the recommendations of the vendor). Adequate steam flow is represented by turbine bypass valves at least 30% open, or total steam flow ≥ 10^6 lb/hr. Reactor startup is allowed prior to performing this SR because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions and provides adequate time to complete the Surveillance. SR 3.5.1.10 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

~~The Frequency is based on the need to perform the Surveillance under the conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

REFERENCES

1. USAR, Section VI-4.3.
2. USAR, Section VI-4.4.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.1 from previous page (not included)

A verification that suppression pool water level is ≥ 12 ft 7 inches ensures that the CS System and LPCI subsystems can supply sufficient makeup water to the RPV with an excess supplementary volume to ensure adequate ECCS pump NPSH.

~~The 12 hour Frequency of these SRs was developed considering operating experience related to suppression pool water level variations and instrument drift during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool water level condition.~~ INSERT 2

SR 3.5.2.2, SR 3.5.2.4, and SR 3.5.2.5

The Bases provided for SR 3.5.1.1, SR 3.5.1.6, and SR 3.5.1.9 are applicable to SR 3.5.2.2, SR 3.5.2.4, and SR 3.5.2.5, respectively.

SR 3.5.2.3

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 applies only to valves affecting the direct flow path. This SR excluded valves that, if mispositioned, would not affect system or subsystem OPERABILITY. Also, 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. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. ~~The 31 day Frequency is appropriate because the valves are operated under procedural control and the probability of their being mispositioned during this time period is low.~~ INSERT 2

BASES

ACTIONS (continued)

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCI System is simultaneously inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig 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 3.5.3.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge line of the RCIC System full of water ensures that the system will perform properly, injecting its full capacity into the Reactor Coolant System upon demand. This will also prevent a water hammer following an initiation signal. One acceptable method of ensuring the line is full is to vent at the high points. ~~The 31 day Frequency is based on the gradual nature of void buildup in the RCIC piping, the procedural controls governing system operation, and operating experience.~~ INSERT 2

SR 3.5.3.2

Verifying the correct alignment for manual, power operated, and automatic valves in the RCIC flow path provides assurance that the proper flow path will exist for RCIC operation. This SR applies only to valves affecting the direct flow path. This SR excludes valves that, if mispositioned, would not affect system or subsystem OPERABILITY. Also, 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. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to

BASES

SURVEILLANCE REQUIREMENTS (continued)

valves that cannot be inadvertently misaligned, such as check valves. For the RCIC System, this SR also includes the steam flow path for the turbine and the flow controller position.

~~The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve position would affect only the RCIC System. This Frequency has been shown to be acceptable through operating experience.~~

INSERT 2

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow against a system head corresponding to reactor pressure is tested both at the higher and lower operating ranges of the system. The required system head should overcome the RPV pressure and associated discharge line losses. Adequate reactor steam pressure must be available to perform these tests. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the RCIC System diverts steam flow. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Adequate reactor steam pressure to perform SR 3.5.3.3 is 920 psig and 145 psig to perform SR 3.5.3.4. Adequate steam flow is represented by turbine bypass valves at least 30% open, or total steam flow $\geq 10^6$ lb/hr. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure Surveillance has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Therefore, these SRs are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are

BASES

SURVEILLANCE REQUIREMENTS (continued)

adequate to perform the test. The 12 hours allowed for the flow tests after the required pressure and flow are reached are sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SRs. For SR 3.5.3.4, while adequate pressure can be reached prior to the required Applicability for RCIC, the 12 hour allowance of the Note would not apply until entering the Applicability (>150 psig) with adequate steam flow.

~~A 92 day Frequency for SR 3.5.3.3 is consistent with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.3.4 is based on the need to perform the Surveillance under conditions that apply just prior to or during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

SR 3.5.3.5

The RCIC System is required to actuate automatically in order to verify its design function satisfactorily. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of the RCIC System will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence; that is, automatic pump startup and actuation of all automatic valves to their required positions. This test also ensures the RCIC System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the ECST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2 overlaps this Surveillance to provide complete testing of the assumed design function.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if these particular procedures were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.1.2 from previous page (not included)

does not change by more than the calculated amount per minute over a 10 minute period. ~~The leakage test is performed every 24 months. The 24 month Frequency was developed considering it is prudent that this Surveillance be performed during a unit outage and also in view of the fact that component failures that might have affected this test are identified by other primary containment SRs.~~ INSERT 2 Two consecutive test failures, however, would indicate unexpected primary containment degradation; in this event, as the Note indicates, increasing the Frequency to once every 9 months is required until the situation is remedied as evidenced by passing two consecutive tests.

REFERENCES

1. USAR, Section V-2.4.
2. USAR, Section XIV-6.3.
3. 10 CFR 50, Appendix J, Option B.
4. 10 CFR 50.36(c)(2)(ii).
5. Safety Evaluation Report by U.S. Atomic Energy Commission dated February 14, 1973 (Section 6.2.1)

BASES

SURVEILLANCE REQUIREMENTS (continued)

successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door 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 are applicable to SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C primary containment leakage rate.

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure, closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary 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 inner and outer door opening will not inadvertently occur. ~~Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when primary containment 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. 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 primary containment OPERABILITY if the Surveillance were performed with the reactor at power. The 24 month Frequency is based on engineering judgement and is considered adequate given that the interlock is not challenged during use of the airlock.~~ INSERT 2

REFERENCES

1. USAR, Section V-2.3.4.5.
2. Safety Evaluation Report by U.S. Atomic Energy Commission dated February 14, 1973 (Section 6.2.1).
3. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1 (continued)

Only one SGT subsystem is allowed to be operating when the 24 inch purge and vent valves are open, due to the potential damage the filters would experience from excessive differential pressure caused by a LOCA, to ensure at least one SGT subsystem is OPERABLE following a LOCA. If a LOCA occurs when the 24 inch purge and vent valves are open, these valves are capable of closing in the environment following the LOCA. Therefore, these valves are allowed to be open for limited periods of time. ~~The 31 day Frequency is consistent with other PCIV requirements discussed in SR 3.6.1.3.2.~~ INSERT 2

SR 3.6.1.3.2

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. This SR does not apply to valves and blind flanges that are locked, sealed, or otherwise secured in the correct position, since these valves were verified to be in the correct position upon locking, sealing, or securing.

This SR does not require any testing or valve manipulation. Rather, it involves verification that those PCIVs outside primary containment, and capable of being mispositioned, are in the correct position. ~~Since verification of valve position for PCIVs outside primary containment is relatively easy, the 31 day Frequency was chosen to provide added assurance that the PCIVs are in the correct positions.~~ INSERT 2

Two Notes have been added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.3 (continued)

controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.4

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. ~~The 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.~~ INSERT 2

SR 3.6.1.3.5

Verifying the isolation time of each power operated automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.6. The isolation time test ensures that 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 requirements of the Inservice Testing Program.

SR 3.6.1.3.6

Verifying that the isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA and transient analyses. This ensures that the

(continued)

SURVEILLANCE REQUIREMENTS (continued)

calculated radiological consequences of these events remain within 10 CFR 100 limits. The Frequency of this SR is in accordance with the requirements of the Inservice Testing Program.

SR 3.6.1.3.7

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. ~~The 24 month Frequency was developed considering it is prudent that this Surveillance be performed only during a unit outage since isolation of penetrations would disrupt the normal operation of many critical components. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

SR 3.6.1.3.8

This SR requires a demonstration that a representative sample of reactor instrumentation line excess flow check valves (EFCVs) are OPERABLE by verifying that each valve actuates to the isolation position on an actual or simulated instrument line break. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested at least once every 10 years (nominal). This SR provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during the postulated instrument line break event. ~~The 24 month Frequency is based on the need to perform the 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.~~ INSERT 2

The nominal 10 year interval is based on other performance-based testing programs, such as Inservice Testing (snubbers) and Option B to 10 CFR 50, Appendix J. Furthermore, any EFCV failures will be evaluated to determine if additional testing in that test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.9

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired. ~~The Frequency of 24 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.4).~~ INSERT 2

SR 3.6.1.3.10

The analyses in References 8 and 9 are based on leakage that is less than the specified leakage rate. A leakage rate of 150 scfh per Main Steam line at $\geq P_a$ (58 psig) was assumed in the LOCA analyses. The equivalent leakage rate at $\geq P_t$ (29 psig) is 106 scfh. An "MSIV line" is each one of the four Main Steam lines with an inboard and an outboard Main Steam Isolation Valve (MSIV). The leakage rate to be measured is the Main Steam line "minimum path" leakage (the lesser actual pathway leakage of the two MSIVs in the Main Steam Line). The leakage limit is based on the analyses of References 11 and 12. The Frequency is in accordance with the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.3.11

Verifying each inboard 24 inch primary containment purge and vent valve (PC-230 MV, PC-231 MV, PC-232 MV, and PC-233 MV) is blocked to restrict the maximum opening angle to 60° is required to ensure that the valves can close under DBA conditions within the times assumed in the analysis of References 7 and 8. If a LOCA occurs, the purge and vent valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times, pressurization concerns are not present, thus the purge valves can be fully open. ~~The 24 month Frequency is appropriate because the blocking devices may be removed during a refueling outage.~~ INSERT 2

SR 3.6.1.3.12

The Main Steam Pathway is the analyzed leakage path from the four Main Steam lines and the inboard Main Steam drain line to and including the condenser. The leakage limit imposed on the Main Steam Pathway with this surveillance requirement applies to the total (aggregate) leakage for the Main Steam Pathway. The Main Steam Pathway leakage includes the total leakage of all four Main Steam line penetrations plus

BASES

ACTIONS

A.1

With drywell pressure not within the limit of the LCO, drywell pressure must be restored within 1 hour. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If drywell pressure cannot be restored to within 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 12 hours and to MODE 4 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 3.6.1.4.1

Verifying that drywell pressure is within limit ensures that unit operation remains within the limit assumed in the primary containment analysis. ~~The 12 hour Frequency of this SR was developed, based on operating experience related to trending of drywell pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell pressure condition.~~ INSERT 2

REFERENCES

1. USAR, Section V-2.
2. 10 CFR 50.36(c)(2)(ii).
3. Safety Evaluation Report by the U.S. Atomic Energy Commission dated February 14, 1973 (Section 6.2.1).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.5.1 from previous page (not included)

~~The 24 hour Frequency of the SR was developed based on operating experience related to drywell average air temperature variations and temperature instrument drift during the applicable MODES and the low probability of a DBA occurring between surveillances. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell air temperature condition.~~ INSERT 2

REFERENCES

1. USAR, Section XIV-6.3.
2. USAR, Table V-2-1.
3. 10 CFR 50.36(c)(2)(ii).
4. USAR, Section VI-5.

BASES

ACTIONS (continued)

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 3.6.1.6.1

A manual actuation of each LLS valve is performed to verify that the valve and solenoids are functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control or bypass valve, by a change in the measured steam flow, or by any other method that is suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Adequate pressure at which this test is to be performed is ≥ 500 psig (consistent with the recommendations of the vendor). Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the LLS valves divert steam flow upon opening. Adequate steam flow is represented by turbine bypass valves at least 30% open, or total steam flow ≥ 10^6 lb/hr. ~~The 24 month Frequency was based on the SRV tests required by the ASME Code for Operation and Maintenance of Nuclear Power Plants (Ref. 3). Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

Since steam pressure is required to perform the Surveillance, however, and steam may not be available during a unit outage, the Surveillance may be performed during the startup following a unit outage. Unit startup is allowed prior to performing the test because valve OPERABILITY and the setpoints for overpressure protection are verified by Reference 3 prior to valve installation. After adequate reactor steam dome pressure and flow are reached, 12 hours is allowed to prepare for and perform the test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.6.2

The LLS designated SRVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the LLS function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.3, "Low—Low Set (LLS) Instrumentation," overlaps this SR to provide complete testing of the safety function.

~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if those particular procedures were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~

INSERT 2

This SR is modified by a Note that excludes valve actuation. This prevents a reactor pressure vessel pressure blowdown.

REFERENCES

1. 10 CFR 50.36(c)(2)(ii).

2. NEDE-22197, Safety Relief Valve Low Low Set System and Lower MSIV Water Level Trip for Cooper Nuclear Station, Unit 1, December 1982.

3. ASME Code for Operation and Maintenance of Nuclear Power Plants.

BASES

ACTIONS (continued)

D.1

With two lines with one or more vacuum breakers inoperable for opening, the primary containment boundary is intact. However, in the event of a containment depressurization, the function of the vacuum breakers is lost. Therefore, all vacuum breakers in one line must be restored to OPERABLE status within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

E.1 and E.2

If any Required Action and associated Completion Time cannot be 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 12 hours and to MODE 4 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 3.6.1.7.1

Each vacuum breaker is verified to be closed to ensure that a potential breach in the primary containment boundary is not present. This Surveillance is performed by observing local or control room indications of vacuum breaker position. ~~The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.~~ INSERT 2

Two Notes are added to this SR. The first Note allows reactor building-to-suppression chamber vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers. The second Note is included to clarify that vacuum breakers open due to an actual differential pressure are not considered as failing this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.7.2

Each vacuum breaker must be cycled to ensure that it opens properly to perform its design function and returns to its fully closed position. This ensures that the safety analysis assumptions are valid. ~~The 92 day Frequency of this SR was developed based upon Inservice Testing Program requirements to perform valve testing at least once every 92 days.~~ INSERT 2

SR 3.6.1.7.3

Demonstration of vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of ≤ 0.5 psid is valid. ~~The 24 month Frequency is based on the need to perform some of the surveillance procedures which satisfy this SR under the conditions that apply during a plant outage and the potential for an unplanned transient if these particular procedures were performed with the reactor at power. For this unit, the 24 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other Surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.~~ INSERT 2

REFERENCES

1. Bodega Bay Preliminary Hazards Summary Report, Appendix I, Docket 50-205, December 28, 1962.

2. USAR, Section V-2.3.6.

3. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

C.1 and C.2

If any Required Action and associated Completion Time cannot be 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 12 hours and to MODE 4 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 3.6.1.8.1

Each vacuum breaker is verified closed (except when the vacuum breaker is performing its intended design function) to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker position indication or by performing a leak test that confirms that the bypass area between the drywell and suppression chamber is less than or equivalent to a one inch diameter hole. If the bypass test fails, not only must the vacuum breaker(s) be considered open and the appropriate Conditions and Required Actions of this LCO be entered, but also the appropriate Conditions and Required Actions of LCO 3.6.1.1, Primary Containment, must be entered. ~~The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.~~ INSERT 2

A Note is added to this SR which allows suppression chamber-to-drywell vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers.

SR 3.6.1.8.2

Each required vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the safety analysis assumptions are valid. ~~The 31 day Frequency of this SR was developed, based on Inservice Testing Program~~

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~requirements to perform valve testing at least once every 92 days. A 31-day Frequency was chosen to provide additional assurance that the vacuum breakers are OPERABLE, since they are located in a harsh environment (the suppression chamber airspace).~~ INSERT 2

SR 3.6.1.8.3

Verification of the vacuum breaker setpoint for opening is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of 0.5 psid is valid. ~~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 an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.~~ INSERT 2

REFERENCES

1. Bodega Bay Preliminary Hazards Summary Report, Appendix I, Docket 50-205, December 28, 1962.

2. USAR, Section XIV-6.3.

3. Deleted

4. USAR, Section V-2.3.6.

5. 10 CFR 50.36(c)(2)(ii).

6. FSAR Question No. 5.17.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.9.1 (continued)

~~The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.~~

INSERT 2

SR 3.6.1.9.2

Verifying each required RHR pump develops a flow rate > 7700 gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded during the cycle. It is tested in the pool cooling mode to demonstrate pump OPERABILITY without spraying down equipment in the drywell. Flow is a normal test of centrifugal pump performance required by the ASME Code, Section XI (Ref. 4). This test confirms one point on the pump performance curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.1.9.3

This Surveillance is performed following maintenance which could result in nozzle blockage by introduction of air to verify that the spray nozzles are not obstructed and that flow will be provided when required. The Frequency is adequate to detect degradation in performance due to the passive nozzle design and its normally dry state and has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Chapter XIV, Section 6.3.

2. USAR, Chapter V, Section 2.

3. EE 01-035, EQ Temperature Profile in Containment based on Small Steam Line Break and DBA-LOCA Analysis.

4. ASME, Boiler and Pressure Vessel Code, Section XI.

BASES

ACTIONS

D.1, D.2, and D.3 (continued)

experience. Given the high suppression pool average temperature in this Condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

E.1 and E.2

If suppression pool average temperature cannot be maintained at ≤ 120°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < 200 psig within 12 hours, and the plant must be brought to at least MODE 4 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.

Continued addition of heat to the suppression pool with suppression pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure. Furthermore, if a blowdown were to occur when the temperature was > 120°F, the maximum allowable bulk temperature could be exceeded very quickly.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. The average temperature is determined by taking an arithmetic average of OPERABLE suppression pool water temperature channels. ~~The 24 hour Frequency has been shown, based on operating experience, to be acceptable. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently.~~ The 5 minute Frequency during testing is justified by the rates at which tests will heat up the suppression pool, has been shown to be acceptable based

INSERT 2

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1 (continued)

on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The ~~Frequencies are~~ Frequency is further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. USAR, Section V-2.
2. USAR, Section XIV-6.
3. USAR, Section XIV-5.
4. NEDC 94-034D.
5. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS

A.1 (continued)

operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within limits. Also, it takes into account the low probability of an event impacting the suppression pool water level occurring during this interval.

B.1 and B.2

If suppression pool water level 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 12 hours and to MODE 4 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 3.6.2.2.1

Verification of the suppression pool water level is to ensure that the required limits are satisfied. ~~The 24 hour Frequency has been shown to be acceptable based on operating experience. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool water level condition.~~

INSERT 2

REFERENCES

1. USAR, Section V-2.
2. 10 CFR 36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1 (continued)

position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable since the RHR suppression pool cooling mode is manually initiated. 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 Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.~~ INSERT 2

SR 3.6.2.3.2

Verifying that each RHR pump develops a flow rate ≥ 7700 gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by ASME Code (Ref. 4). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. USAR, Section XIV-6.
2. 10 CFR 36(c)(2)(ii).
3. NEDC 94-034B, C & D
4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

BASES

ACTIONS (continued)

B.1

If oxygen concentration 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, power must be reduced to ≤ 15% RTP within 8 hours. The 8 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.1

The primary containment must be determined to be inert by verifying that oxygen concentration is < 4.0 v/o. ~~The 7 day Frequency is based on the slew rate at which oxygen concentration can change and on other indications of abnormal conditions (which would lead to more frequent checking by operators in accordance with plant procedures). Also, this Frequency has been shown to be acceptable through operating experience.~~ INSERT 2

REFERENCES

1. USAR, Section XIV-6.3.
2. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS

C.1 and C.2 (continued)

movement of recently irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. Momentary transients on installed instrumentation due to gusty wind conditions are considered acceptable and are not cause for failure to meet this SR. ~~The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations during the applicable MODES and the low probability of a DBA occurring between surveillances.~~

~~Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.~~

INSERT 2

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches and one access door in each access opening are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. SR 3.6.4.1.2 also requires equipment hatches to be sealed. In this application, the term "sealed" has no connotation of leak tightness. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed. However, each secondary containment access door is normally kept closed, except when the access opening is being used for normal transient entry and exit or when maintenance is being performed on an access. ~~The 31 day Frequency for these SRs has been shown to be adequate, based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator~~.

INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.1.4

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. SR 3.6.4.1.4 demonstrates that one SGT subsystem can maintain ≥ 0.25 inches of vacuum water gauge for 1 hour at a flow rate ≤ 1780 cfm. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. Therefore, this test is used to ensure secondary containment boundary integrity. Since this SR is a secondary containment test, it need not be performed with each SGT subsystem. ~~The SGT subsystems are tested on a STAGGERED TEST BASIS, however, to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

REFERENCES

1. USAR, Section XIV-6.3.
2. USAR, Section XIV-6.4.
3. 10 CFR 50.36(c)(2)(ii).

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies that each secondary containment manual isolation valve and blind flange that is not locked, sealed, or otherwise secured and is 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 secondary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those SCIVs in secondary containment that are capable of being mispositioned are in the correct position.

INSERT 2

~~Since these SCIVs are readily accessible to personnel during normal operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide added assurance that the SCIVs are in the correct positions.~~ This SR does not apply to valves and blind flanges 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.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these isolation devices, once they have been verified to be in the proper position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.

SR 3.6.4.2.2

Verifying that the isolation time of each power operated automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to minimize leakage of radioactive material from secondary containment following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. ~~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 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 at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

REFERENCES

1. USAR, Section V-3.0.
2. USAR, Section XIV-6.0.
3. USAR, Section XIV-6.3.
4. USAR, Section XIV-6.4
5. 10 CFR 50.36(c)(2)(ii).
6. Technical Requirements Manual.

BASES

ACTIONS (continued)

D.1

If both SGTS subsystems are inoperable in MODE 1, 2, or 3, the SGT system may not be capable of supporting the required radioactivity release control function. Therefore, actions are required to enter LCO 3.0.3 immediately.

E.1 and E.2

When two SGT subsystems are inoperable, if applicable, movement of recently irradiated fuel assemblies in secondary containment must immediately be suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action E.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving recently irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of recently irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGT subsystem, including each filter train fan, for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on for ≥ 10 continuous hours ~~every 31 days~~ eliminates moisture on the adsorbers and HEPA filters. ~~The 31 day Frequency was developed in consideration of the known reliability of~~ INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~fan motors and controls and the redundancy available in the system.~~

SR 3.6.4.3.2

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

SR 3.6.4.3.3

This SR verifies that each SGT subsystem starts on receipt of an actual or simulated initiation signal. ~~While this Surveillance can be performed with the reactor at power, operating experience has shown that these components will pass the Surveillance when performed at the 24 month Frequency.~~ The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. ~~Therefore, the Frequency was found to be acceptable from a reliability standpoint.~~

INSERT 2

SR 3.6.4.3.4

This SR verifies that the SGT units cross tie damper is in the correct position, and that each SGT room air supply check valve and each air operated SGT dilution air shutoff valve open when required. This ensures that the decay heat removal function of SGT System operation is available. ~~While this Surveillance can be performed with the reactor at power, operating experience has shown that these components will pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was found to be acceptable from a reliability standpoint.~~

INSERT 2

REFERENCES

1. (Deleted)
2. USAR, Section V-3.3.4.
3. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.1 from previous page (not included)

in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

~~The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.~~ INSERT 2

REFERENCES

1. USAR, Section X-8.2.
2. USAR, Table VIII-5-1.
3. USAR, Chapter XIV.
4. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

B.1 and B.2

If the SW subsystem cannot be restored to OPERABLE status within the associated Completion Time, or both SW subsystems are inoperable, or the UHS is determined inoperable 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 12 hours and in MODE 4 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 3.7.2.1

This SR verifies the river water level to be sufficient for the proper operation of the SW pumps (net positive suction head and pump vortexing are considered in determining this limit). ~~The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.~~ INSERT 2

SR 3.7.2.2

Verification of the UHS temperature ensures that the heat removal capability of the SW System is within the assumptions of the DBA analysis. ~~The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.~~ INSERT 2

SR 3.7.2.3

Verifying the correct alignment for each manual, power operated, and automatic valve in each SW subsystem flow path provides assurance that the proper flow paths will exist for SW operation. This SR applies only to valves affecting the direct flow path. This SR excludes valves that, if mispositioned, would not affect system or subsystem OPERABILITY. Also, 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. A valve is also allowed to be in the nonaccident position, and yet considered in the correct position, provided it can be automatically realigned to its accident

BASES

SURVEILLANCE REQUIREMENTS (continued)

position within the required time. 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.

This SR is modified by a Note indicating that isolation of the SW System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the SW System. As such, when all SW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the SW System is still OPERABLE.

~~The 31-day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.~~ INSERT 2

SR 3.7.2.4

This SR verifies that the automatic isolation valves of the SW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by the use of an actual or simulated initiation signal. The initiation signal is caused by low SW header pressure (approximately 20 psig). This SR also verifies that the SW pumps with their mode selector switch in AUTO will automatically start on a low SW header pressure.

~~Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.~~ INSERT 2

REFERENCES

1. NEDC 94-255, "Hydraulic Evaluation of Opening in Intake Structure Guide Wall," June 14, 1995.

2. USAR, Chapter V.

3. USAR, Chapter XIV.

4. 10 CFR 50.36(c)(2)(ii).

5. NEDC 00-095E, "CNS Reactor Building Post-LOCA Heating Analysis," May 28, 2010.

BASES

ACTIONS (continued)

days. With the unit in this condition, the remaining OPERABLE REC subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE REC subsystem could result in loss of REC function.

The 30 day Completion Time is based on the redundant REC System capabilities afforded by the OPERABLE subsystem and the low probability of an accident occurring during this time period.

C.1 and C.2

If the REC subsystem cannot be restored to OPERABLE status within the associated Completion Time, leakage exceeds limits with both SW backup subsystems inoperable, or both REC subsystems are inoperable, 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 12 hours and in MODE 4 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 3.7.3.1

This SR verifies the water level in the REC surge tank to be sufficient for the proper operation of the REC System (system volume changes, static pressure in the loops, and potential leakage in the system are considered in determining this limit). If REC leakage exceeds limits, the REC subsystems are considered OPERABLE but degraded. ~~The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.~~ INSERT 2

This SR is modified by two Notes. Note 1 states that SR 3.0.1 is not applicable when both SW backup subsystems are OPERABLE. Note 2 states that REC leakage beyond limits by itself is only a degraded condition and does not render the REC System inoperable. These notes reflect that the REC System remains OPERABLE based on the ability to align the SW System to the REC System and supply the required cooling water to the critical loops of the REC System.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.3.2

Verification of the REC System temperature ensures that the heat removal capability of the REC System is within the assumptions of the DBA analysis. ~~The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.~~ INSERT 2

SR 3.7.3.3

Verifying the correct alignment for each manual, power operated, and automatic valve in each REC subsystem flow path provides assurance that the proper flow paths will exist for REC operation. 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. A valve is also allowed to be in the nonaccident position, and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required time. 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.

This SR is modified by a Note indicating that isolation of the REC System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the REC System. As such, when all REC pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the REC System is still OPERABLE.

~~The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.~~ INSERT 2

SR 3.7.3.4

This SR verifies that the automatic isolation valves of the REC System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by the use of an actual or simulated initiation signal. The initiation signal is caused by low REC heat exchanger outlet pressure (which has an analytically determined limit of 55 psig decreasing). Also, a Group VI isolation signal will open the REC

BASES

SURVEILLANCE REQUIREMENTS (continued)

heat exchanger service water outlet valves and the REC critical loop supply valves to provide cooling water to essential components.

~~Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.~~

INSERT 2

REFERENCES

1. USAR, Section X-6.
2. 10 CFR 50.36(c)(2)(ii).
3. DC 93-057
4. NEDC 92-050X and NEDC 97-087

BASES

ACTIONS (continued)

these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

on its required frequency

This SR verifies that the CREF System in a standby mode starts on demand and continues to operate. The system should be checked periodically to ensure that it starts and functions properly. As the environmental and normal operating conditions of this system are not severe, testing the system ~~once every month~~ provides an adequate check on this system. Since the CREF System does not contain heaters, the system need only be operated for ≥ 15 minutes to demonstrate the function of the system. ~~The 31 day Frequency is based on the known reliability of the equipment.~~

INSERT 2

SR 3.7.4.2

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

SR 3.7.4.3

This SR verifies that on an actual or simulated initiation signal, the CREF System starts and operates. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.7.1, "Control Room Emergency Filter (CREF) System Instrumentation," overlaps this SR to provide complete testing of the safety function. ~~The Frequency of 24 months is based on industry operating experience and is consistent with the typical refueling cycle.~~

INSERT 2

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR~~, on a 31 day Frequency,~~ requires an isotopic analysis of a representative offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled are Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88. If the measured rate of radioactivity, as indicated by the Condenser Air Ejector Noble Gas Activity Monitor, increases significantly (by ≥ 50% after correcting for expected increases due to changes in THERMAL POWER), an isotopic analysis is also performed within 4 hours after the increase is noted, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. ~~The 31 day Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable, based on operating experience.~~ INSERT 2

This SR is modified by a Note indicating that the SR is not required to be performed until 31 days after any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Air Ejector Offgas System at significant rates.

REFERENCES

1. Letter from J. M. Pilant (NPPD) to G. E. Lear (NRC) "Failed Fuel Pin Detection Capability," dated March 2, 1978.

2. 10 CFR 100.

3. 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABILITY

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

ACTIONS

A.1

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, because irradiated fuel assembly movement can occur in MODE 1, 2, or 3, Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

When the initial conditions for an accident cannot be met, action must be taken to preclude the accident from occurring. If the spent fuel storage pool level is less than required, the movement of irradiated fuel assemblies in the spent fuel storage pool is suspended immediately. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that sufficient water is available in the event of a fuel handling accident. The water level in the spent fuel storage pool must be checked periodically. ~~The 7 day Frequency is acceptable, based on operating experience, considering that the water volume in the pool is normally stable, and all water level changes are controlled by unit procedures.~~ INSERT 2

REFERENCES

1. USAR, Section X-3.0.
2. USAR, Section XIV-6.4.
3. Not used.
4. 10 CFR 50.67.
5. Regulatory Guide 1.183, July 2000.

BASES

ACTIONS (continued)

sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the Applicable Safety Analyses transients. The 4 hour 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 3.7.7.1

Cycling each main turbine bypass valve through at least half of one cycle of full travel (50% open) demonstrates that the valves are mechanically OPERABLE and will function when required. ~~The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Operating experience has shown that these components usually pass the SR when performed at the 31 day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.~~ INSERT 2

SR 3.7.7.2

The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. ~~The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24 month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.~~ INSERT 2

Cycling open a bypass valve at slightly above 29.5 RTP may affect the RPS Turbine Stop and Control Valve functions.

SR 3.7.7.3

This SR ensures that the TURBINE BYPASS SYSTEM RESPONSE TIME is in compliance with the assumptions of the appropriate safety analyses. The response time limits are specified in the COLR. ~~The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed~~

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~with the reactor at power. Operating experience has shown the 24 month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.~~ INSERT 2

REFERENCES

1. USAR, Section VII-11.3.
2. Amendment 25 to the FSAR.
3. NEDC 96-006, "Estimate of Steam Tunnel's HELB," March 3, 1996.
4. USAR, Section XIV-5.8.1.
5. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.1 from previous page (not included)

independence of offsite circuits is maintained. This can be accomplished by verifying that a critical bus is energized and that the status of offsite supply breakers displayed in the control room is correct. ~~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.~~ INSERT 2

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and 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, these SRs have been modified by a Note (Note 2 for SR 3.8.1.2 and Note 1 for SR 3.8.1.7) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and (only for SR 3.8.1.2) followed by a warmup prior to loading.

For the purposes of this testing, the DGs are manually started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being periodically circulated and temperature is being maintained consistent with manufacturer recommendations.

In order to reduce stress and wear on diesel engines, the manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3 to SR 3.8.1.2, which is only applicable when such modified start procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that~~, at a 184 day Frequency,~~ the DG starts from standby conditions and achieves required voltage and frequency within 14 seconds. The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not dampened by load application. This period may be extended beyond the 14 second acceptance criterion and could be cause for failing the SR. In lieu of a time constraint in the SR, monitoring and trending of the actual

BASES

SURVEILLANCE REQUIREMENTS (continued)

time to reach steady state operation will be performed as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The 14 second start requirement supports the assumptions in the design basis LOCA analysis of USAR, Section VIII-5.2 (Ref. 13). The 14 second start requirement is not applicable to SR 3.8.1.2 (see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 14 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 does require a 14 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This procedure is the intent of Note 1 of SR 3.8.1.2.

~~The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 9). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.~~ INSERT 2

SR 3.8.1.3

This Surveillance provides assurance that the DGs are capable of synchronizing and accepting greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 2 hours is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0 while synchronized to the grid. Since the generator is rated at a particular KVA at 0.8 power factor, the 0.8 value is the design rating of the machine. The 1.0 value is an operational condition where the reactive power component is zero, which minimizes the reactive heating of the generator. Operating the generator at a power factor between 0.8 lagging and 1.0 avoids adverse conditions associated with underexciting the generator and more closely represents the generator operating requirements when performing its safety function (running isolated on its associated critical bus). Because each DG is rated at 4000 kW at 0.8 power factor (pf), the required load band is ≥ 3600 kW at ≥ 0.8 pf (≥ 90% of rated load, in accordance with Regulatory Guide 1.9, Ref. 9) and less than or equal to rated load. This load band brackets the maximum expected accident loads. The load band is provided to avoid routine overloading of the DG.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

~~The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 9).~~ INSERT 2

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized.

Note 2 modifies this Surveillance by stating 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 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for approximately 3.9 hours of DG operation at full load.

~~The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.~~ INSERT 2

SR 3.8.1.5

Periodic removal

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 oil day tanks ~~once every 31 days~~ eliminates the necessary environment for bacterial survival. This is the most effective means of

BASES

SURVEILLANCE REQUIREMENTS (continued)

controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and 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 Frequency is consistent with Regulatory Guide 1.137 (Ref. 11).~~ This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance. INSERT 2

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and automatically transfers fuel oil from the storage tanks to the associated day tank. It is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump 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 Frequency for this SR corresponds to the testing requirements for pumps as contained in the ASME Code for Operation and Maintenance of Nuclear Power Plants (Ref. 14).~~ INSERT 2

SR 3.8.1.8

Transfer of each 4.16 kV critical bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. ~~The 24 month Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed on the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.~~ INSERT 2

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.9

Consistent with IEEE 387-1995 (Ref. 15), Section 7.5.9 and Table 3, this SR requires demonstration ~~once per 24 months~~ that the DGs can start and run continuously at full load capability for an interval of not less than 8 hours - 6 hours of which is at a load equivalent to 90-100% of the continuous rating of the DG, and 2 hours of which is at a load equivalent to 105% to 110% of the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

A load band of 90-100% accident load is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Generator loadings less than 90% occurring during the first 10 seconds of accident loading are bounded by the test conditions of 90 to 100% load and are well within the generator capability curves.

~~The 24 month Frequency is consistent with IEEE 387-1995 (Ref. 15), Section 7.5.9 and Table 3, which require this SR to be performed during refueling outages once per 24 months. The 24 month Frequency takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.~~ INSERT 2

This Surveillance has been modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. Note 3 ensures that the DG is tested under load conditions that are as close to worst case design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.89. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. Under certain conditions, however, Note 3 allows the surveillance to be conducted at a power factor other than ≤ 0.89. These conditions occur when grid voltage is high, and the additional field

BASES

SURVEILLANCE REQUIREMENTS (continued)

excitation needed to obtain a power factor of ≤ 0.89 results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.89 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor of 0.89 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained as close as practicable to 0.89 without exceeding the DG excitation limits. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.10

Under LOCA conditions and loss of offsite power, loads are sequentially connected to the bus by a timed logic sequence. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

~~The Frequency of 24 months is consistent with the intent of the recommendations of Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(2); takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.~~ INSERT 2

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.11

In the event of a DBA coincident with a loss of offsite power, the DGs 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 DG operation during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This test verifies all actions encountered from the loss of offsite power and loss of coolant accident, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically maintain the required voltage and frequency.

The DG auto-start time of 14 seconds is derived from requirements of the accident analysis for responding 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 has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG 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 systems are not capable of being operated at full flow. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system 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 Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 24 months.~~ INSERT 2

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being periodically circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. USAR, Section VIII-1.0.

2. USAR, Section VIII-2.0 and VIII-3.0.

3. Safety Guide 9, Revision 0, March 1971.

BASES

REFERENCES (continued)

4. USAR, Chapter VI.

5. USAR, Chapter XIV.

6. 10 CFR 50.36(c)(2)(ii).

7. Generic Letter 84-15.

8. Regulatory Guide 1.93.

9. Regulatory Guide 1.9, Revision 3, July 1993.

10. Regulatory Guide 1.108.

11. Regulatory Guide 1.137.

12. ANSI C84.1, 1970.

13. USAR, Section VIII-5.2.

14. ~~ASME Code for Operation and Maintenance of Nuclear Power Plants.~~ Not used.

15. IEEE Standard 387, 1995.

BASES

ACTIONS (continued)

prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time of Condition A, B, C, D, or E not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A, B, C, D, or E, the associated DG(s) may be incapable of performing its intended function and must be immediately declared inoperable.

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 a single DG's operation for 7 days at maximum post-LOCA load demand. The 7 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 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.~~ INSERT 2

SR 3.8.3.2

This Surveillance ensures that sufficient lubricating oil inventory (combined inventory in the DG lube oil sump and in the warehouse) is available to support at least 7 days of operation for one DG at maximum post-LOCA load demand. The 504 gal requirement is based on a 3 gallon per hour consumption value for the run time of the DG. Implicit in this SR is the requirement to verify that adequate DG lube oil is stored onsite to ensure that sump level does not drop below the manufacturer's recommended minimum level.

BASES

SURVEILLANCE REQUIREMENTS (continued)

~~A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run time are closely monitored by the plant staff.~~ INSERT 2

SR 3.8.3.3

The tests of new fuel oil prior to addition to the storage tanks 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 prior to adding the new fuel to the storage tank(s), but in no case is the time between the sample (and corresponding test results) including receipt of new fuel and addition of new fuel oil to the storage tanks to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-1988 (Ref. 8);

b. Verify in accordance with the tests specified in ASTM D975-1989a (Ref. 8) that: (1) the sample has an API gravity of within 0.3° at 60°F or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate, or the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 26° and ≤ 38°; (2) a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, or a Saybolt viscosity at 100°F of ≥ 32.6 and ≤ 40.1 if gravity was not determined by comparison with the supplier's certification; and (3) a flash point of ≥ 125°F; and

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-1991 (Ref. 8) or a water and sediment content of ≤ 0.05% volume when tested in accordance with ASTM D1796-1983 (Ref. 8).

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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.4 from previous page (not included)

requirements provide for multiple engine start cycles without recharging. The pressure specified in this SR is intended to reflect the lowest value at which the requirements of Reference 7 can be satisfied.

~~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.~~

INSERT 2

SR 3.8.3.5

Periodic removal

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 31 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 DG operation. Water may come from any of several sources, including condensation, ground water, rain water, 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 consistent with Regulatory Guide 1.137 (Ref. 2), as supplemented by ANSI N195 (Ref. 3). This SR is for preventive maintenance.~~ The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed to the extent possible during performance of the Surveillance.

INSERT 2

REFERENCES

1. USAR, Section VIII-5.2.
2. Regulatory Guide 1.137, Revision 1, October 1979.
3. ANSI N195, Appendix B, 1976.
4. USAR, Chapter VI.
5. USAR, Chapter XIV.
6. 10 CFR 50.36(c)(2)(ii).
7. USAR, Section VIII-5.3.3.

BASES

ACTIONS (continued)

reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 4 is consistent with the time required in Regulatory Guide 1.93 (Ref. 6).

C.1

With the Division 1 250 V DC electrical power subsystem inoperable, one LPCI subsystem is rendered inoperable. Loss of the Division 2 250 V DC electrical power subsystem renders HPCI and the other LPCI subsystem inoperable. Required Action C.1 therefore requires with one 250 V DC electrical power subsystem inoperable that the associated supported features be declared inoperable immediately. This declaration also requires entry into applicable Conditions and Required Actions for the associated supported features.

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 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. Terminal voltage while on float charge is determined by multiplying the number of cells in the battery by minimum float voltage for the battery's nominal SG. At CNS, battery cells are designed for a nominal SG of 1.215 +/- 0.005. Minimum cell float voltage for SG of 1.215 is 2.17 volts per cell (Vpc). The 125 VDC systems have 58 cells connected in series and the 250 VDC systems have 120 cells connected in series. Multiplying 2.17 Vpc by 58 cells yields minimum voltage for 125 V batteries of 125.9. Multiplying 2.17 Vpc by 120 cells yields minimum voltage for 250 V batteries of 260.4. ~~The 7 day Frequency is conservative when compared with the manufacturer's recommendations and IEEE 450 (Ref. 7).~~ INSERT 2

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 limits for battery connection resistance are specified in Table 3.8.4-1.

For inter-cell, inter-tier, and terminal connections, the limits are 150 micro-ohm. For inter-rack connections, the limit is 280 micro-ohm.

The total resistance of the batteries is also monitored. This total resistance is the sum of the inter-cell connectors, the inter-tier cables and connectors, the inter-rack cables and connectors, and the terminal connections. The limits for total resistance in the load and voltage studies are 3355 micro-ohm for the 125 volt batteries (Ref. 11 and 12), 6595 micro-ohm for Division 1 of the 250 volt battery (Ref. 13), and 6775 micro-ohm for Division 2 of the 250 volt battery (Ref. 14). The total resistance limits in Table 3.8.4-1 are conservative two significant digit expressions of the calculated limits.

~~The 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.~~ INSERT 2

SR 3.8.4.3

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 18 month Frequency for the Surveillance is based on engineering judgement. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency has been concluded to be acceptable from a reliability standpoint.~~ INSERT 2

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 provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion 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 this Surveillance.

The limits for battery connection resistance are specified in Table 3.8.4-1.

For inter-cell, inter-tier, and terminal connections, the limits are 150 micro-ohm. For inter-rack connections, the limit is 280 micro-ohm.

The total resistance of the batteries is also monitored. This total resistance is the sum of the inter-cell connectors, the inter-tier cables and connectors, the inter-rack cables and connectors, and the terminal connections. The limits for total resistance in the load and voltage studies are 3355 micro-ohm for the 125 volt batteries (Ref. 11 and 12), 6595 micro-ohm for Division 1 of the 250 volt battery (Ref. 13), and 6775 micro-ohm for Division 2 of the 250 volt battery (Ref. 14). The total resistance limits in Table 3.8.4-1 are conservative two significant digit expressions of the calculated limits.

~~The 18 month Frequency for the Surveillances is based on engineering judgment. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency has been concluded to be acceptable from a reliability standpoint.~~ INSERT 2

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 3). According to Regulatory Guide 1.32 (Ref. 8), the battery charger supply is required 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

~~The Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.~~ INSERT 2

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in design calculations.

~~The Frequency of 24 months is consistent with the intent of the recommendations of Regulatory Guide 1.32 (Ref. 8) and Regulatory Guide 1.129 (Ref. 9), which state that the battery service test should be performed during refueling operations or at some other outage.~~ INSERT 2

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test ~~once per 60 months~~. The substitution is acceptable because a modified performance discharge test represents a more severe test of battery capacity than SR 3.8.4.7.

The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

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.

A battery modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance discharge test, both of which envelope the

BASES

SURVEILLANCE REQUIREMENTS (continued)

duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. 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.

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. 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.

The acceptance criteria of ≥ 90% capacity for this Surveillance is conservative with respect to IEEE-450 (Ref. 7) and IEEE-485 (Ref. 10). 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.

INSERT 2

~~The Frequency for this test is normally 60 months.~~ If the battery shows degradation, or if the battery has reached 15 years (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. 7), when the battery capacity drops by more than 10% relative to its capacity on the previous performance tests or when it is below 90% of the manufacturer's rating. However, at Cooper Nuclear Station degradation is defined when the battery capacity drops by more than 5% relative to the capacity on the previous performance test or when the battery capacity ≤ 95% of the manufacturer's rating. This more restrictive definition of degradation is necessary to ensure that the decision can be made for battery replacement before the ≥ 90% capacity technical specification is violated. All these frequencies are consistent with the recommendations in IEEE-450 (Ref. 7).

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

REFERENCES

1. USAR, Section VIII-6.2.
2. Regulatory Guide 1.6.
3. IEEE Standard 308, 1970.
4. USAR, Chapter XIV.
5. 10 CFR 50.36(c)(2)(ii).
6. Regulatory Guide 1.93.
7. IEEE Standard 450, 1995.
8. Regulatory Guide 1.32, February 1977.
9. ~~Regulatory Guide 1.129, December 1974.~~ Not used.
10. IEEE Standard 485, 1983.
11. NEDC 87-131C, 125 VDC Division I Load and Voltage Study.
12. NEDC 87-131D, 125 VDC Division II Load and Voltage Study.
13. NEDC 87-131A, 250 VDC Division I Load and Voltage Study.
14. NEDC 87-131B, 250 VDC Division II Load and Voltage Study.

BASES

ACTIONS (continued)

of representative cells < 70°F, also are 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. 3), which recommends regular battery inspections ~~(at least one per month)~~ including voltage, specific gravity, and electrolyte temperature of pilot cells.

INSERT 2

SR 3.8.6.2

periodic

INSERT 2

The ~~quarterly~~ inspection ~~of~~ specific gravity and voltage is consistent with IEEE-450 (Ref. 3). ~~In~~ addition, within 24 hours of a battery discharge < 105 V for a 125 V battery and < 210 V for a 250 V battery, or a battery overcharge > 140 V for a 125 V battery or > 280 V for a 250 V battery, the affected 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, or < 210 V, as applicable, 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. 3), 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.

is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells is within limits ~~is consistent with a recommendation of IEEE-450 (Ref. 3) 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's recommendations and the battery sizing calculations.

BASES

ACTIONS (continued)

requires entry into applicable Conditions and Required Actions for the associated supported features.

E.1

Condition E corresponds to a level of degradation in the electrical power distribution system that causes a required safety function to be lost. When more than one AC or DC electrical power distribution subsystem is lost, and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical buses are maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. ~~The 7 day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.~~

INSERT 2

REFERENCES

1. USAR, Chapter XIV.
2. 10 CFR 50.36(c)(2)(ii).
3. Regulatory Guide 1.93, December 1974.

BASES

SURVEILLANCE REQUIRMENTS

SR 3.8.8.1

This Surveillance verifies that the AC and DC electrical power distribution subsystems are functioning properly, with the correct breaker alignment. The correct breaker alignment ensures power is available to each required bus. The verification of proper voltage availability on the bus ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. ~~The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that alert the operator to subsystem malfunctions.~~ INSERT 2

REFERENCES

1. USAR, Chapter XIV.
2. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

Alternatively, Required Actions A.2.1 and A.2.2 will permit continued fuel movement with the interlocks inoperable if a control rod withdrawal block is inserted, and all control rods are subsequently verified to be fully inserted. Required Action A.2.1 (rod block) ensures no control rods can be withdrawn. The withdrawal block utilized must ensure that if rod withdrawal is requested, the rod will not respond (i.e., it will remain inserted). Required Action A.2.2 is performed after placing the rod withdrawal block in effect, and provides a verification that all control rods are fully inserted. This verification that all control rods are fully inserted is in addition to the periodic verifications required by SR 3.9.3.1.

Like Required Action A.1, Required Actions A.2.1 and A.2.2 ensure unacceptable operations are blocked (e.g., loading fuel into a cell with the control rod withdrawn).

One use for the A.2 Required Actions is to permit performance of SR 3.9.1.1 once, prior to fuel movement, without the need for subsequent performance if the fuel movement extends longer than the 7 day Frequency of the SR. This permits continued fuel movement under the protection of the continuous rod block inserted by the Required Actions.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

~~The 7 day Frequency is based on engineering judgment and is considered adequate in view of other indications of refueling interlocks and their associated input status that are available to unit operations personnel.~~ INSERT 2

REFERENCES

1. USAR, Appendix F, Section F-2.5.
2. USAR, Section VII-6.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.2.1 from previous page (not included)

Therefore, this Surveillance imposes an additional level of assurance that the refueling position one-rod-out interlock will be OPERABLE when required. By "locking" the reactor mode switch in the proper position (i.e., removing the reactor mode switch key from the console while the reactor mode switch is positioned in refuel), an additional administrative control is in place to preclude operator errors from resulting in unanalyzed operation.

~~The Frequency of 12 hours is sufficient in view of other administrative controls utilized during refueling operations to ensure safe operation.~~

INSERT 2

SR 3.9.2.2

Performance of a CHANNEL FUNCTIONAL TEST on each channel demonstrates the associated refuel position one-rod-out interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested. ~~The 7-day Frequency is considered adequate because of demonstrated circuit reliability, procedural controls on control rod withdrawals, and visual and audible indications available in the control room to alert the operator to control rods not fully inserted.~~ To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position). Therefore, SR 3.9.2.2 has been modified by a Note that states the CHANNEL FUNCTIONAL TEST is not required to be performed until 1 hour after any control rod is withdrawn.

INSERT 2

REFERENCES

1. USAR, Appendix F, Section F-2.5.
2. USAR, Section VII-6.
3. USAR, Section XIV-5.3.3.
4. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1 (continued)

~~The 12 hour Frequency takes into consideration the procedural controls on control rod movement during refueling as well as the redundant functions of the refueling interlocks.~~ INSERT 2

REFERENCES

1. USAR, Appendix F, Section F-2.5.
2. USAR, Section VII-6.
3. USAR, Section XIV-5.3.3.
4. USAR, Section XIV-5.3.4.
5. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2 (continued)

automatic insertion and the associated CRD scram accumulator pressure is ≥ 940 psig.

~~The 7 day Frequency takes into consideration equipment reliability, procedural controls over the scram accumulators, and control room alarms and indicating lights that indicate low accumulator charge pressures.~~ INSERT 2

SR 3.9.5.1 is modified by a Note that allows 7 days after withdrawal of the control rod to perform the Surveillance. This acknowledges that the control rod must first be withdrawn before performance of the Surveillance, and therefore avoids potential conflicts with SR 3.0.3 and SR 3.0.4.

REFERENCES

1. USAR, Appendix F, Section F-2.5.
2. USAR, Section XIV-5.3.3.
3. USAR, Section XIV-5.3.4.
4. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 21 ft above the top of the RPV flange ensures that the design basis for the postulated refueling accident analysis during refueling operations is met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a refueling accident in containment (Ref. 1).

~~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 on valve positions, which make significant unplanned level changes unlikely.~~ INSERT 2

REFERENCES

1. USAR, Section XIV-6.4
2. USAR, Section X-3.0.
3. 10 CFR 50.67.
4. 10 CFR 50.36(c)(2)(ii).
5. Regulatory Guide 1.183, July 2000.

BASES

ACTIONS

B.1, B.2, B.3, and B.4 (continued)

operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment is indicated). This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, a surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

C.1 and C.2

If no RHR shutdown cooling subsystem is in operation, an alternate method of coolant circulation is required to be established within 1 hour. The Completion Time is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem), the reactor coolant temperature must be periodically monitored to ensure proper functioning of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

This Surveillance demonstrates that the required RHR shutdown cooling subsystem is in operation and circulating reactor coolant.

The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. ~~The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the~~

INSERT 2

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1 (continued)

~~operator for monitoring the RHR shutdown cooling subsystem in the control room.~~

REFERENCES

1. USAR, Section IV-8.0.
2. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS

B.1, B.2 and B.3 (continued)

other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

C.1 and C.2

If no RHR subsystem is in operation, an alternate method of coolant circulation is required to be established within 1 hour. The Completion Time is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem), the reactor coolant temperature must be periodically monitored to ensure proper functioning of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.9.8.1

This Surveillance demonstrates that one RHR shutdown cooling subsystem is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability.

~~The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR shutdown cooling subsystems in the control room.~~ INSERT 2

REFERENCES

1. USAR, Section IV-8.0
2. 10 CFR 50.36(c)(2)(ii).

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.10.2.1 and SR 3.10.2.2

Meeting the requirements of this Special Operations LCO maintains operation consistent with or conservative to operating with the reactor mode switch in the shutdown position (or the refuel position for MODE 5). The functions of the reactor mode switch interlocks that are not in effect, due to the testing in progress, are adequately compensated for by the Special Operations LCO requirements. The administrative controls are to be periodically verified to ensure that the operational requirements continue to be met. ~~The Surveillances performed at the 12 hour and 24 hour Frequencies are intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.~~ INSERT 2

REFERENCES

1. USAR, Section VII-2.3.7.
2. USAR, Section XIV-5.3.3.
3. USAR, Section XIV-5.3.4.
4. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3 (continued)

SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements, since SR 3.10.3.2 demonstrates that the alternative LCO 3.10.3.d.2 requirements are satisfied. Also, SR 3.10.3.3 verifies that all control rods other than the control rod being withdrawn are fully inserted. ~~The 24 hour frequency is acceptable because of the administrative controls on control rod withdrawal, the protection afforded by the LCOs involved, and hardwire interlocks that preclude additional control rod withdrawals.~~ INSERT 2

REFERENCES

1. USAR, Section VII-6.4.
2. USAR, Section XIV-5.3.3.
3. 10 CFR 50.36(c)(2)(ii).

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.10.4.1, SR 3.10.4.2, SR 3.10.4.3, and SR 3.10.4.4

The other LCOs made applicable by this Special Operations LCO are required to have their associated surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification is required to ensure that the possibility of criticality remains precluded. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. Verification that all the other control rods are fully inserted is required to meet the SDM requirements. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the affected control rod. ~~The 24 hour frequency is acceptable because of the administrative controls on control rod withdrawals, the protection afforded by the LCOs involved, and hardwire interlocks to preclude an additional control rod withdrawal.~~

INSERT 2

SR 3.10.4.2 and SR 3.10.4.4 have been modified by Notes, which clarify that these SRs are not required to be met if the alternative requirements demonstrated by SR 3.10.4.1 are satisfied.

REFERENCES

1. USAR, Section VII-6.4.
2. USAR, Section XIV-5.3.3.
3. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5 (continued)

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. ~~The 24 hour Frequency is acceptable, given the administrative controls on control rod removal and hardwire interlock to block an additional control rod withdrawal.~~

INSERT 2

REFERENCES

1. USAR, Section VII-6.4.
2. USAR, Section XIV-6.4.
3. 10 CFR 50.36(c)(2)(ii).

BASES

LCO (continued)

room operator and a licensed operator and a member of the reactor engineering staff on the refueling floor shall verify that the control rod is inserted in the core cell to be loaded. Otherwise, all control rods must be fully inserted before loading fuel.

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The exceptions from other LCO requirements (e.g., the ACTIONS of LCO 3.9.3, LCO 3.9.4, or LCO 3.9.5) allowed by this Special Operations LCO are appropriately controlled by requiring all fuel to be removed from cells whose "full-in" indications are allowed to be bypassed. This bypassing must be verified by two licensed operators (Reactor Operator or Senior Reactor Operator).

ACTIONS

A.1, A.2, A.3.1, and A.3.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for refueling (i.e., all control rods inserted in core cells containing one or more fuel assemblies) or with the exceptions granted by this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2, Required Action A.3.1, and Required Action A.3.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the affected CRDs and insert their control rods, or initiate action to restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.6.1, SR 3.10.6.2, and SR 3.10.6.3

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. In addition, SR 3.10.6.1 must be verified by one licensed operator (Reactor Operator or Senior Reactor Operator) and one member of the reactor engineering staff. ~~The 24 hour~~ INSERT 2

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.6.1, SR 3.10.6.2, and SR 3.10.6.3 (continued)

~~Frequency is acceptable, given the administrative controls on fuel assembly and control rod removal, and takes into account other indications of control rod status available in the control room.~~

REFERENCES

1. USAR, Section VII-6.4.
2. Deleted
3. USAR, Section XIV-5.3.3.
4. 10 CFR 50.36(c)(2)(ii).

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1, SR 3.10.8.2, and SR 3.10.8.3

LCO 3.3.1.1, Functions 2.a and 2.e, made applicable in this Special Operations LCO, are required to have applicable Surveillances met to establish that this Special Operations LCO is being met (SR 3.10.8.1). However, the control rod withdrawal sequences during the SDM tests may be enforced by the RWM (LCO 3.3.2.1, Function 2, MODE 2 requirements) or by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other qualified member of the technical staff. As noted, either the applicable SRs for the RWM (LCO 3.3.2.1) must be satisfied according to the applicable Frequencies (SR 3.10.8.2), or the proper movement of control rods must be verified (SR 3.10.8.3). This latter verification (i.e., SR 3.10.8.3) must be performed during control rod movement to prevent deviations from the specified sequence. These Surveillances provide adequate assurance that the specified test sequence is being followed.

SR 3.10.8.4

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis. ~~The 12 hour frequency is intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.~~

INSERT 2

SR 3.10.8.5

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The verification is required to be performed any time a control rod is withdrawn to the "full-out" notch position, or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.8.5 (continued)

Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved as well as operating experience related to uncoupling events.

SR 3.10.8.6

CRD charging water header pressure verification is performed to ensure the motive force is available to scram the control rods in the event of a scram signal. Since the reactor is depressurized in MODE 5, there is insufficient reactor pressure to scram the control rods. Verification of charging water header pressure ensures that if a scram were to be required, capability for rapid control rod insertion would exist. The minimum pressure of 940 psig is well below the expected pressure of 1100 psig, while still ensuring sufficient pressure for rapid control rod insertion. ~~The 7 day frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.~~ INSERT 2

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, Supplement for United States (Revision specified in the COLR).

2. Letter from T. Pickens (BWROG) to G.C. Lainas, NRC, "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," August 15, 1986.

3. 10 CFR 50.36(c)(2)(ii).

Attachment 6

TSTF-425 (NUREG-1433) versus CNS TS Cross-Reference

Cooper Nuclear Station, Docket No. 50-298, License No. DPR-46

TSTF-425 vs. CNS Cross-Reference

Technical Specification Section Title/Surveillance Description*	TSTF-425 (NUREG1433)	CNS
Control Rod Operability	**3.1.3**	**3.1.3**
Control rod position	3.1.3.1	3.1.3.1
Notch test - fully withdrawn control rod one notch	3.1.3.2	-
Notch test - partially withdrawn control rod one notch	3.1.3.3	3.1.3.3
Control Rod Scram Times	**3.1.4**	**3.1.4**
Scram time testing	3.1.4.2	3.1.4.2
Control Rod Scram Accumulators	**3.1.5**	**3.1.5**
Control rod scram accumulator pressure	3.1.5.1	3.1.5.1
Rod Pattern Control	**3.1.6**	**3.1.6**
Control rods comply with Banked Position Withdrawal Sequence	3.1.6.1	3.1.6.1
Standby Liquid Control (SLC) System	**3.1.7**	**3.1.7**
Volume of sodium pentaborate (Level of pentaborate in SLC tank)	3.1.7.1	3.1.7.1
Temperature of sodium pentaborate solution	3.1.7.2	3.1.7.2
Temperature of pump suction piping	3.1.7.3	3.1.7.3
Continuity of explosive charge	3.1.7.4	3.1.7.4
Concentration of boron solution (sodium pentaborate)	3.1.7.5	3.1.7.5
Manual/power operated valve position	3.1.7.6	3.1.7.6
Pump flow rate	3.1.7.7	3.1.7.7**
Flow through one SLC subsystem	3.1.7.8	3.1.7.8
Heat traced piping is unblocked	3.1.7.9	3.1.7.9
Scram Discharge Volume (SDV) Vent & Drain Valves	**3.1.8**	**3.1.8**
Each SDV vent & drain valve open	3.1.8.1	3.1.8.1
Cycle each SDV vent & drain valve closes on receipt of scram	3.1.8.2	3.1.8.2
Each SDV vent & drain valve closes on receipt of scram	3.1.8.3	3.1.8.3
Average Planar Linear Heat Generation Rate (APLHGR)	**3.2.1**	**3.2.1**
APLHGR less than or equal to limits	3.2.1.1	3.2.1.1
Minimum Critical Power Ratio (MCPR)	**3.2.2**	**3.2.2**
MCPR greater than or equal to limits	3.2.2.1	3.2.2.1
Linear Heat Generation Rate (LHGR)	**3.2.3**	**3.2.3**
LHGR less than or equal to limits	3.2.3.1	3.2.3.1
Average Power Range Monitor (APRM) Gain & Setpoints	**3.2.4**	**-**
Maximum Fraction of Limiting Power Density (MFLPD) is within limits	3.2.4.1	-
APRM setpoints or gain are adjusted for calculated MFLPD	3.2.4.2	-
Reactor Protection System (RPS) Instrumentation	**3.3.1.1**	**3.3.1.1**
Channel Check	3.3.1.1.1	3.3.1.1.1
Absolute difference between APRM channels & calculated power	3.3.1.1.2	3.3.1.1.2
Adjust channel to conform to calibrated flow	3.3.1.1.3	3.3.1.1.7
Channel Functional Test (12 hours after entering Mode 2)	3.3.1.1.4	3.3.1.1.3
Channel Function Test (weekly)	3.3.1.1.5	3.3.1.1.4

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Verify Intermediate Range Monitor and APRM overlap	-	3.3.1.1.6
Calibrate local power range monitors	3.3.1.1.6	3.3.1.1.8
Channel Functional Test	3.3.1.1.7	3.3.1.1.9
Calibrate trip units	3.3.1.1.8	-
Channel Calibration	3.3.1.1.9	3.3.1.1.10
Channel Functional Test	3.3.1.1.10	3.3.1.1.11
Channel Calibration	3.3.1.1.11	3.3.1.1.12
Verify APRM Flow Biased Simulated Thermal Power - High	3.3.1.1.12	-
Logic System Functional Test	3.3.1.1.13	3.3.1.1.13
Verify Turbine Stop Valve-Turbine Control Valve (TSV/TCV) closure/Trip Oil Press-Low Not Bypassed	3.3.1.1.14	3.3.1.1.14
Verify RPS Response Time	3.3.1.1.15	3.3.1.1.15
Source Range Monitor (SRM) Instrumentation	**3.3.1.2**	**3.3.1.2**
Channel Check	3.3.1.2.1	3.3.1.2.1
Verify Operable SRM Detector	3.3.1.2.2	3.3.1.2.2
Channel Check	3.3.1.2.3	3.3.1.2.3
Verify count rate	3.3.1.2.4	3.3.1.2.4
Channel Functional Test (Mode 5)	3.3.1.2.5	3.3.1.2.5
Channel Functional Test (Modes 2, 3, 4)	3.3.1.2.6	3.3.1.2.6
Channel Calibration	3.3.1.2.7	3.3.1.2.7
Control Rod Block Instrumentation	**3.3.2.1**	**3.3.2.1**
Channel Functional Test - Rod Block Monitor (RBM)	3.3.2.1.1	3.3.2.1.1
Channel Functional Test - Rod Worth Minimizer (RWM) (Mode 2)	3.3.2.1.2	3.3.2.1.2
Channel Functional Test - RWM (Mode 1)	3.3.2.1.3	3.3.2.1.3
Verify RBM upscale function not bypassed	3.3.2.1.4	3.3.2.1.4
Verify RWM not bypassed	3.3.2.1.5	3.3.2.1.6
Channel Functional Test - Reactor Mode Switch (Shutdown position)	3.3.2.1.6	3.3.2.1.7
Channel Calibration - RBM	3.3.2.1.7	3.3.2.1.5
Feedwater & Main Turbine High Water Level Trip Instrumentation	**3.3.2.2**	**3.3.2.2**
Channel Check	3.3.2.2.1	3.3.2.2.1
Channel Functional Test	3.3.2.2.2	-
Channel Calibration	3.3.2.2.3	3.3.2.2.2
Logic System Functional Test	3.3.2.2.4	3.3.2.2.3
Post Accident Monitor (PAM) Instrumentation	**3.3.3.1**	**3.3.3.1**
Channel Check	3.3.3.1.1	3.3.3.1.1
Channel Calibration	3.3.3.1.2	3.3.3.1.2/ 3.3.3.1.3
Remote Shutdown System	**3.3.3.2**	**3.3.3.2**
Channel Check	3.3.3.2.1	3.3.3.2.1
Verify control circuit and transfer switch capable of function	3.3.3.2.2	3.3.3.2.2
Channel Calibration	3.3.3.2.3	3.3.3.2.3

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End-of-Cycle (EOC) Recirculation Pump Trip (RPT) Instrumentation	**3.3.4.1**	-
Channel Functional Test	3.3.4.1.1	-
Calibrate trip units	3.3.4.1.2	-
Channel Calibration	3.3.4.1.3	-
Logic System Functional Test	3.3.4.1.4	-
Verify TSV/TCV Closure/Trip Oil Press-Low Not Bypassed	3.3.4.1.5	-
Verity EOC-RPT System Response Time	3.3.4.1.6	-
Determine RPT breaker interruption time	3.3.4.1.7	-
Anticipated Trip Without Scram-RPT Instrumentation	**3.3.4.2**	**3.3.4.1**
Channel Check	3.3.4.2.1	-
Channel Functional Test	3.3.4.2.2	3.3.4.1.1
Calibrate trip units	3.3.4.2.3	-
Channel Calibration	3.3.4.2.4	3.3.4.1.2
Logic System Functional Test	3.3.4.2.5	3.3.4.1.3
Emergency Core Cooling System (ECCS) Instrumentation	**3.3.5.1**	**3.3.5.1**
Channel Check	3.3.5.1.1	3.3.5.1.1
Channel Functional Test	3.3.5.1.2	3.3.5.1.2
Calibrate trip units	3.3.5.1.3	-
Channel Calibration	3.3.5.1.4	3.3.5.1.3
Channel Calibration	3.3.5.1.5	3.3.5.1.4
Logic System Functional Test	3.3.5.1.6	3.3.5.1.5
Verify ECCS Response Time	3.3.5.1.7	-
Reactor Core Isolation Cooling (RCIC) System Instrumentation	**3.3.5.2**	**3.3.5.2**
Channel Check	3.3.5.2.1	3.3.5.2.1
Channel Functional Test	3.3.5.2.2	3.3.5.2.2
Calibrate trip units	3.3.5.2.3	-
Channel Calibration	3.3.5.2.4	3.3.5.2.3
Channel Calibration	3.3.5.2.5	3.3.5.2.4
Logic System Functional Test	3.3.5.2.6	3.3.5.2.5
Primary Containment Isolation Instrumentation	**3.3.6.1**	**3.3.6.1**
Channel Check	3.3.6.1.1	3.3.6.1.1
Channel Functional Test	3.3.6.1.2	3.3.6.1.2
Calibrate trip units	3.3.6.1.3	-
Channel Calibration	3.3.6.1.4	3.3.6.1.3
Channel Functional Calibration	3.3.6.1.5	-
Channel Calibration	3.3.6.1.6	3.3.6.1.4
Calibrate each radiation detector	-	3.3.6.1.5
Logic System Functional Test	3.3.6.1.7	3.3.6.1.6
Verify Isolation Response Time	3.3.6.1.8	-

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Secondary Containment Isolation Instrumentation	**3.3.6.2**	**3.3.6.2**
Channel Check	3.3.6.2.1	3.3.6.2.1
Channel Functional Test	3.3.6.2.2	3.3.6.2.2
Calibrate trip units	3.3.6.2.3	-
Channel Calibration	3.3.6.2.4	-
Channel Calibration	3.3.6.2.5	3.3.6.2.3
Logic System Functional Test	3.3.6.2.6	3.3.6.2.4
Verify Isolation Response Time	3.3.6.2.7	-
Low-Low-Set (LLS) Instrumentation	**3.3.6.3**	**3.3.6.3**
Channel Check	3.3.6.3.1	-
Channel Functional Test	3.3.6.3.2	3.3.6.3.1
Channel Functional Test	3.3.6.3.3	3.3.6.3.2
Channel Functional Test	3.3.6.3.4	3.3.6.3.3
Calibrate trip units	3.3.6.3.5	-
Channel Calibration	3.3.6.3.6	3.3.6.3.4
Logic System Functional Test	3.3.6.3.7	3.3.6.3.5
Main Control Room Environmental Control (Control Room Emergency Filter System [CREFS] for CNS)	**3.3.7.1**	**3.3.7.1**
Channel Check	3.3.7.1.1	3.3.7.1.1
Channel Functional Test	3.3.7.1.2	3.3.7.1.2
Calibrate trip units	3.3.7.1.3	-
Channel Calibration	3.3.7.1.4	3.3.7.1.3
Logic System Functional Test	3.3.7.1.5	3.3.7.1.4
Loss of Power (LOP) Instrumentation	**3.3.8.1**	**3.3.8.1**
Channel Check	3.3.8.1.1	-
Channel Functional Test	3.3.8.1.2	3.3.8.1.1
Channel Calibration	3.3.8.1.3	3.3.8.1.2
Logic System Functional Test	3.3.8.1.4	3.3.8.1.3
RPS Electric Power Monitoring	**3.3.8.2**	**3.3.8.2**
Channel Functional Test	3.3.8.2.1	-
Channel Calibration	3.3.8.2.2	3.3.8.2.1
System Functional Test	3.3.8.2.3	3.3.8.2.2
Recirculation Loops Operating	**3.4.1**	**3.4.1**
Recirculation loop jet pump flow mismatch with both loops operating	3.4.1.1	3.4.1.1
Verify not in Stability Exclusion Region	-	3.4.1.2
Jet Pumps	**3.4.2**	**3.4.2**
Criterial Satisfied for each operating recirculation loop	3.4.2.1	3.4.2.1
Safety/Relief Valves (SRVs) [and Safety Valves (SVs)]	**3.4.3**	**3.4.3**
Safety function lift setpoints	3.4.3.1	3.4.3.1**
Verify SRV opens when manually actuated	3.4.3.2	3.4.3.2
Reactor Coolant System (RCS) Operational Leakage	**3.4.4**	**3.4.4**
RCS unidentified and total leakage increase within limits	3.4.4.1	3.4.4.1

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RCS Pressure Isolation Valve (PIV) Leakage	**3.4.5**	-
PIV Leakage within limits	3.4.5.1	-
RCS Leakage Detection Instrumentation	**3.4.6**	**3.4.5**
Channel Check	3.4.6.1	3.4.5.1
Channel Functional Test	3.4.6.2	3.4.5.2
Channel Calibration of required leak detection instrumentation	3.4.6.3	3.4.5.3
RCS Specific Activity	**3.4.7**	**3.4.6**
Dose Equivalent I-131 specific activity	3.4.7.1	3.4.6.1
Residual Heat Removal (RHR) Shutdown Cooling - Hot Shutdown	**3.4.8**	**3.4.7**
One RHR Shutdown cooling subsystem operating	3.4.8.1	3.4.7.1
RHR Shutdown Cooling - Cold Shutdown	**3.4.9**	**3.4.8**
One RHR Shutdown cooling subsystem operating	3.4.9.1	3.4.8.1
RCS Pressure/Temperature Limit	**3.4.10**	**3.4.9**
RCS pressure, temperature, heatup and cooldown rates	3.4.10.1	3.4.9.1
Reactor Pressure Vessel (RPV) flange/head flange temperatures (tensioning head bolt stud)	3.4.10.7	3.4.9.5
RPV flange/head flange temperatures (after RCS temp ≤ 80°F)	3.4.10.8	3.4.9.6
RPV flange/head flange temperatures (after RCS temp ≤ 100°F)	3.4.10.9	3.4.9.7
Reactor Steam Dome Pressure	**3.4.11**	**3.4.10**
Verify reactor steam dome pressure	3.4.11.1	3.4.10.1
ECCS - Operating	**3.5.1**	**3.5.1**
Verify injection/spray piping filled with water	3.5.1.1	3.5.1.1
Verify each valve in flow path is in correct position	3.5.1.2	3.5.1.2
Verify Automatic Depressurization System (ADS) nitrogen pressure	3.5.1.3	3.5.1.3
Verify RHR cross tie valve is closed and power removed	3.5.1.4	3.5.1.4
Verify LPCI inverter output voltage	3.5.1.5	-
Verify ECCS pumps develop specified flow	3.5.1.7	3.5.1.6**
Verify High Pressure Coolant Injection (HPCI) flow rate (Rx press ≤ 1020, ≥ 920)	3.5.1.8	3.5.1.7
Verify HPCI flow rate (Rx press ≤ 165)	3.5.1.9	3.5.1.8
Verify ECCS actuates on initiation signal	3.5.1.10	3.5.1.9
Verify ADS actuates on initiation signal	3.5.1.11	3.5.1.10
Verify each ADS valve opens [actuator strokes] when manually actuated	3.5.1.12	3.5.1.11
ECCS - Shutdown	**3.5.2**	**3.5.2**
Verify, for LPCI, suppression pool water level (Including Core Spray [CS] for CNS)	3.5.2.1	3.5.2.1
Verify, for CS, suppression pool water level and Condensate Storage Tank water level	3.5.2.2	-
Verify ECCS piping filled with water	3.5.2.3	3.5.2.2
Verify each valve in flow path is in correct position	3.5.2.4	3.5.2.3

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Verify pumps develop flow rate	3.5.2.5	3.5.2.4**
Verify ECCS actuates on initiation signal	3.5.2.6	3.5.2.5
Reactor Core Isolation Cooling (RCIC) System	**3.5.3**	**3.5.3**
Verify RCIC piping filled with water	3.5.3.1	3.5.3.1
Verify each valve in flow path is in correct position	3.5.3.2	3.5.3.2
Verify RCIC flow rate	3.5.3.3	3.5.3.3
Verify RCIC flow rate (Rx press ≤ 165)	3.5.3.4	3.5.3.4
Verify RCIC actuates on initiation signal	3.5.3.5	3.5.3.5
Primary Containment	**3.6.1.1**	**3.6.1.1**
Verify drywell to suppression chamber bypass leakage	3.6.1.1.2	3.6.1.1.2
Primary Containment Airlock	**3.6.1.2**	**3.6.1.2**
Verify only one airlock door can be opened at a time	3.6.1.2.2	3.6.1.2.2
Primary Containment Isolation Valves (PCIVs)	**3.6.1.3**	**3.6.1.3**
Verify purge valve is closed	3.6.1.3.1	-
Verify each 24 inch primary purge valve is closed	3.6.1.3.2	3.6.1.3.1
Verify each manual PCIV outside containment is closed	3.6.1.3.3	3.6.1.3.2
Verify continuity of traversing incore probe (TIP) shear valve	3.6.1.3.5	3.6.1.3.4
Verify PCIV isolation times (except Main Steam Isolation Valves [MSIVs])	3.6.1.3.6	3.6.1.3.5**
Perform leak rate testing for valves with resilient seals	3.6.1.3.7	-
Verify isolation time of MSIVs	3.6.1.3.8	3.6.1.3.6**
Verify automatic PCIV actuates to isolation position	3.6.1.3.9	3.6.1.3.7
Verify sample of Excess Flow Check Valves actuate to isolation position	3.6.1.3.10	3.6.1.3.8
Test explosive squib from each shear valve	3.6.1.3.11	3.6.1.3.9
Verify purge valve is blocked to restrict valve opening	3.6.1.3.15	3.6.1.3.11
Drywell/Containment Pressure	**3.6.1.4**	**3.6.1.4**
Verify drywell pressure is within limit	3.6.1.4.1	3.6.1.4.1
Drywell Average Air Temperature	**3.6.1.5**	**3.6.1.5**
Verify drywell average air temperature is within limit	3.6.1.5.1	3.6.1.5.1
LLS Valves	**3.6.1.6**	**3.6.1.6**
Verify each LLS valve opens when manually actuated	3.6.1.6.1	3.6.1.6.1
Verify LLS system actuates on initiation signal	3.6.1.6.2	3.6.1.6.2
Reactor Building - Suppression Chamber Vacuum Breakers	**3.6.1.7**	**3.6.1.7**
Verify each vacuum breaker is closed	3.6.1.7.1	3.6.1.7.1
Perform functional test on each vacuum breaker	3.6.1.7.2	3.6.1.7.2
Verify opening setpoint for each vacuum breaker	3.6.1.7.3	3.6.1.7.3
Suppression Chamber - Drywell Vacuum Breakers	**3.6.1.8**	**3.6.1.8**
Verify each vacuum breaker is closed	3.6.1.8.1	3.6.1.8.1
Perform function test on each vacuum breaker	3.6.1.8.2	3.6.1.8.2
Verify opening setpoint for each vacuum breaker	3.6.1.8.3	3.6.1.8.3

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Main Steam Isolation Valve Leakage Control System (LCS)	**3.6.1.9**	**-**
Operate each MSIV LCS blower	3.6.1.9.1	-
Verify continuity of inboard MSIV LCS heater element	3.6.1.9.2	-
Perform functional test of each MSIV LCS subsystem	3.6.1.9.3	-
Suppression Pool Average Temperature	**3.6.2.1**	**3.6.2.1**
Verify suppression pool average temperature within limits	3.6.2.1.1	3.6.2.1.1
Suppression Pool Water Level	**3.6.2.2**	**3.6.2.2**
Verify suppression pool water level within limits	3.6.2.2.1	3.6.2.2.1
RHR Suppression Pool Cooling	**3.6.2.3**	**3.6.2.3**
Verify each valve in flow path is in correct position	3.6.2.3.1	3.6.2.3.1
Verify RHR pump develops flow rate	3.6.2.3.2	3.6.2.3.2**
RHR Suppression Pool Spray (RHR Containment Spray for CNS)	**3.6.2.4**	**3.6.1.9**
Verify each valve in flow path is in correct position	3.6.2.4.1	3.6.1.9.1
Verify RHR pump develops flow rate	3.6.2.4.2	3.6.1.9.2**
Drywell - Suppression Chamber Differential Pressure	**3.6.2.5**	**-**
Verify differential pressure is within limit	3.6.2.5.1	-
Drywell Cooling System Fans	**3.6.3.1**	**-**
Operate each fan ≥ 15 minutes	3.6.3.1.1	-
Verify each fan flow rate	3.6.3.1.2	-
Primary Containment Oxygen Concentration	**3.6.3.2**	**3.6.3.1**
Verify oxygen concentration is within limits	3.6.3.2.1	3.6.3.1.1
Containment Atmosphere Dilution (CAD) System	**3.6.3.3**	**-**
Verify CAD liquid nitrogen storage	3.6.3.3.1	-
Verify each CAD valve in flow path is in correct position	3.6.3.3.2	-
Secondary Containment (SC)	**3.6.4.1**	**3.6.4.1**
Verify SC vacuum is ≥ 0.25 inch of vacuum water gauge	3.6.4.1.1	3.6.4.1.1
Verify all SC equipment hatches closed and sealed	3.6.4.1.2	3.6.4.1.2
Verify one SC access door in each opening is closed	3.6.4.1.3	3.6.4.1.3
Verify SC drawn down using one Standby Gas Treatment (SGT) subsystem	3.6.4.1.4	-
Verify SC can be maintained using on SGT	3.6.4.1.5	3.6.4.1.4
Secondary Containment Isolation Valves (SCIV)	**3.6.4.2**	**3.6.4.2**
Verify each SC isolation manual valve is closed	3.6.4.2.1	3.6.4.2.1
Verify isolation time of each SCIV	3.6.4.2.2	3.6.4.2.2**
Verify each automatic SCIV actuates to isolation position	3.6.4.2.3	3.6.4.2.3
Standby Gas Treatment System	**3.6.4.3**	**3.6.4.3**
Operate each SGT subsystem with heaters operating	3.6.4.3.1	3.6.4.3.1
Verify each SGT subsystem actuates on initiation signal	3.6.4.3.3	3.6.4.3.3
Verify each SGT filter cooler bypass damper can be opened	3.6.4.3.4	3.6.4.3.4
Residual Heat Removal Service Water (RHRSW)	**3.7.1**	**3.7.1**
Verify each RHRSW valve in flow path in correct position.	3.7.1.1	3.7.1.1

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Plant Service Water (PSW) System and Ultimate Heat Sink (UHS)	**3.7.2**	**3.7.2**
Verify water level in Cooling tower basin	3.7.2.1	-
Verify river level	-	3.7.2.1
Verify water level in pump well of pump structure	3.7.2.2	-
Verify average water temperature of heat sink	3.7.2.3	3.7.2.2
Operate each cooling tower fan	3.7.2.4	-
Verify each PSW valve in flow path is in correct position	3.7.2.5	3.7.2.3
Verify PSW actuates on initiation signal	3.7.2.6	3.7.2.4
Diesel Generator (DG) Standby Service Water (SSW) System	**3.7.3**	**-**
Verify valves are in the correct position	3.7.3.1	-
Ensure SSW system pump automatic start	3.7.3.2	-
Reactor Equipment Cooling (REC)	**-**	**3.7.3**
Verify leakage within limits	-	3.7.3.1
Verify temperature	-	3.7.3.2
Verify valves are in the correct position	-	3.7.3.3
Verify each subsystem actuates on actual or simulated signal	-	3.7.3.4
Main Control Room Environmental Control (MCREC) System (Control Room Emergency Filter System for CNS)	**3.7.4**	**3.7.4**
Operate each MCREC subsystem	3.7.4.1	3.7.4.1
Verify each subsystem actuates on initiation signal	3.7.4.3	3.7.4.3
Maintain positive pressure	3.7.4.4	-
Control Room Air Condition System	**3.7.5**	**-**
Verify each subsystem has capability to remove heat load	3.7.5.1	-
Main Condenser Offgas	**3.7.6**	**3.7.5**
Verify gross gamma activity rate of the noble gases	3.7.6.1	3.7.5.1
Main Turbine Bypass System	**3.7.7**	**3.7.7**
Cycle of each main turbine bypass valve	3.7.7.1	3.7.7.1
Perform system functional test	3.7.7.2	3.7.7.2
Verify Turbine Bypass System Response Time within limits	3.7.7.3	3.7.7.3
Spent Fuel Storage Pool Water Level	**3.7.8**	**3.7.6**
Verify spent fuel storage pool water level	3.7.8.1	3.7.6.1
AC Sources - Operating	**3.8.1**	**3.8.1**
Verify correct breaker alignment	3.8.1.1	3.8.1.1
Verify each DG starts from standby conditions/steady state	3.8.1.2	3.8.1.2
Verify each DG is synchronized and loaded	3.8.1.3	3.8.1.3
Verify each day tank level	3.8.1.4	3.8.1.4
Check for and remove accumulated water from day tank	3.8.1.5	3.8.1.5
Verify fuel oil transfer system operates	3.8.1.6	3.8.1.6
Verify each DG starts from standby conditions	3.8.1.7	3.8.1.7
Verify transfer of power from offsite circuit to alternate circuit	3.8.1.8	3.8.1.8
Verify DG rejects load greater than single largest load	3.8.1.9	-

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Verify DG maintains load following load reject	3.8.1.10	-
Verify on loss of offsite power signal	3.8.1.11	-
Verify DG starts on ECCS initiation signal	3.8.1.12	-
Verify DG automatic trips bypassed on ECCS initiation signal	3.8.1.13	-
Verify each DG operates for ≥ 24 hours (≥ 8 hours for CNS)	3.8.1.14	3.8.1.9
Hot Restart	3.8.1.15	-
Verify each DG synchronizes with offsite power	3.8.1.16	-
Verify ECCS initiation signal overrides test mode	3.8.1.17	-
Verify interval between each timed load block	3.8.1.18	3.8.1.10
Verify on Loss of Offsite Power in conjunction with ECCS initiation signal	3.8.1.19	3.8.1.11
Verify simultaneous DG starts	3.8.1.20	-
Diesel Fuel Oil, Lube Oil, and Starting Air	**3.8.3**	**3.8.3**
Verify fuel oil storage tank volume	3.8.3.1	3.8.3.1
Verify lube oil inventory	3.8.3.2	3.8.3.2
Verify each DG air start receiver pressure	3.8.3.4	3.8.3.4
Check/remove accumulated water from fuel oil storage tank	3.8.3.5	3.8.3.5
DC Sources - Operating	**3.8.4**	**3.8.4**
Verify battery terminal voltage	3.8.4.1	3.8.4.1
Verify no visible corrosion or battery connection resistance	-	3.8.4.2
Verify battery cells, plates, racks show no physical damage	-	3.8.4.3
Remove visible corrosion and coat connections	-	3.8.4.4
Verify battery connection resistance	-	3.8.4.5
Verify each battery charger supplies amperage	3.8.4.2	3.8.4.6
Verify battery capacity is adequate to maintain emergency loads	3.8.4.3	3.8.4.7
Verify battery capacity during performance discharge test	-	3.8.4.8
Battery Parameters	**3.8.6**	**3.8.6**
Verify battery meets Category A limits	-	3.8.6.1
Verify battery meets Category B limits	-	3.8.6.2
Verify electrolyte temperature	-	3.8.6.3
Verify battery float current	3.8.6.1	-
Verify battery pilot cell voltage	3.8.6.2	-
Verify battery connected cell electrolyte level	3.8.6.3	-
Verify battery pilot cell temperature	3.8.6.4	-
Verify battery connected cell voltage	3.8.6.5	-
Verify battery capacity during performance discharge test	3.8.6.6	-
Inverters - Operating	**3.8.7**	**-**
Verify correct inverter voltage, frequency and alignment	3.8.7.1	-
Inverters - Shutdown	**3.8.8**	**-**
Verify correct inverter voltage, frequency and alignment	3.8.8.1	-
Distribution System - Operating	**3.8.9**	**3.8.7**
Verify correct breaker alignment/power to distribution subsystems	3.8.9.1	3.8.7.1

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Distribution System - Shutdown	**3.8.10**	**3.8.8**
Verify correct breaker alignment /power to distribution subsystems	3.8.10.1	3.8.8.1
Refueling Equipment Interlocks	**3.9.1**	**3.9.1**
Channel Functional Test of refueling equipment interlock inputs	3.9.1.1	3.9.1.1
Refuel Position One-Rod-Out Interlock	**3.9.2**	**3.9.2**
Verify reactor mode switch locked in refuel position	3.9.2.1	3.9.2.1
Perform Channel Functional Test	3.9.2.2	3.9.2.2
Control Rod Position	**3.9.3**	**3.9.3**
Verify all control rods fully inserted	3.9.3.1	3.9.3.1
Control Rod Operability - Refueling	**3.9.5**	**3.9.5**
Insert each withdrawn control rod one notch	3.9.5.1	3.9.5.1
Verify each withdrawn control rod scram accumulator press	3.9.5.2	3.9.5.2
Reactor Pressure Vessel (RPV) Water Level - Irradiated Fuel (Irradiated and New Fuel for CNS)	**3.9.6**	**3.9.6**
Verify RPV water level	3.9.6.1	3.9.6.1
Reactor Pressure Vessel (RPV) Water Level - New Fuel	**3.9.7**	**-**
Verify RPV water level	3.9.7.1	-
RHR - High Water Level	**3.9.8**	**3.9.7**
Verify one RHR shutdown cooling subsystem operating	3.9.8.1	3.9.7.1
RHR - Low Water Level	**3.9.9**	**3.9.8**
Verify one RHR shutdown cooling subsystem operating	3.9.9.1	3.9.8.1
Reactor Mode Switch Interlock Testing	**3.10.2**	**3.10.2**
Verify all control rods fully inserted in core cells	3.10.2.1	3.10.2.1
Verify no core alterations in progress	3.10.2.2	3.10.2.2
Single Control Rod Withdrawal - Hot Shutdown	**3.10.3**	**3.10.3**
Verify all control rods in five-by-five array are disarmed	3.10.3.2	3.10.3.2
Verify all control rods other than withdrawn rod are fully inserted	3.10.3.3	3.10.3.3
Single Control Rod Withdrawal - Cold Shutdown	**3.10.4**	**3.10.4**
Verify all control rods in five-by-five array are disarmed	3.10.4.2	3.10.4.2
Verify all control rods other than withdrawn rod are fully inserted	3.10.4.3	3.10.4.3
Verify a control rod withdrawal block is inserted	3.10.4.4	3.10.4.4
Single Control Rod Drive (CRD) Removal - Refueling	**3.10.5**	**3.10.5**
Verify all control rods other than withdrawn rod are fully inserted	3.10.5.1	3.10.5.1
Verify all control rods in five-by-five array are disarmed	3.10.5.2	3.10.5.2
Verify a control rod withdrawal block is inserted	3.10.5.3	3.10.5.3
Verify no core alterations in progress	3.10.5.5	3.10.5.5
Multiple CRD Withdrawal - Refueling	**3.10.6**	**3.10.6**
Verify four fuel assemblies removed from core cells	3.10.6.1	3.10.6.1
Verify all other rods in core cells inserted	3.10.6.2	3.10.6.2
Verify fuel assemblies being loaded comply with reload sequence	3.10.6.3	3.10.6.3
Shutdown Margin Test - Refueling	**3.10.8**	**3.10.8**
Verify no core alterations in progress	3.10.8.4	3.10.8.4

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Verify CRD charging water header pressure	3.10.8.6	3.10.8.6
Recirculation Loops - Testing	**3.10.9**	**-**
Verify LCO 3.4.1 requirements suspended for ≤ 24 hours	3.10.9.1	-
Verify Thermal power ≤ 5% RTP during Physics Test	3.10.9.2	-
Training Startups	**3.10.10**	**-**
Verify all operable IRM channels are ≤ 25/40 div. of full scale	3.10.10.1	-
Verify average reactor coolant temperature < 200°F	3.10.10.2	-
Programs (Surveillance Frequency Control Program [SFCP])	**5.5.15**	**5.5.14**

*The Technical Specifications (TS) Section Title/Surveillance Description of this attachment is a summary description of the referenced TSTF 425/CNS TS Surveillances which is provided for information purposes only and is not intended to be a verbatim description of the TS Surveillances.

**This CNS Surveillance Frequency is provided in the CNS Inservice Testing Program. This CNS Surveillance Frequency is not proposed for inclusion in the Surveillance Frequency Control Program.

Attachment 7

Proposed No Significant Hazards Consideration

Cooper Nuclear Station, Docket No. 50-298, License No. DPR-46

Description of Amendment Request:

The change requests the adoption of an approved change to the standard technical specifications (STS) for General Electric Plants, BWR/4 (NUREG-1433), to allow relocation of specific Technical Specifications (TS) surveillance frequencies to a licensee-controlled program. The proposed change is described in Technical Specification Task Force (TSTF) Traveler, TSTF-425, Revision 3 (ADAMS Accession No. ML090850642) related to the Relocation of Surveillance Frequencies to Licensee Control - Risk-Informed Technical Specifications Task Force (RITSTF) Initiative 5b and was described in the Notice of Availability published in the Federal Register on July 6, 2009 (74 FR 31996).

The proposed changes are consistent with Nuclear Regulatory Commission (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 (SFCP). This change is applicable to licensees using probabilistic risk guidelines contained in NRC-approved Nuclear Energy Institute (NEI) 04-10, "Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Method for Control of Surveillance Frequencies," (ADAMS Accession No. 071360456).

Basis for proposed no significant hazards consideration: As required by 10 CFR 50.91(a), the Nebraska Public Power District (NPPD) analysis of the issue of no significant hazards consideration is presented below:

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

   Response: No.

   The proposed change relocates the specified frequencies for periodic surveillance requirements to licensee control under a new SFCP. Surveillance frequencies are not an initiator to any accident previously evaluated. As a result, the probability of any accident previously evaluated is not significantly increased. The systems and components required by the technical specifications for which the surveillance frequencies are relocated are still required to be operable, meet the acceptance criteria for the surveillance requirements, and be capable of performing any mitigation function assumed in the accident analysis. As a result, the consequences of any accident previously evaluated are not significantly increased.

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

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

   Response: No.

No new or different accidents result from utilizing the proposed change. The change does 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 change does not impose any new or different requirements. The change does not alter assumptions made in the safety analysis. The proposed change is consistent with the safety analysis assumptions and current plant operating practice.

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

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

Response: No.

The design, operation, testing methods, and acceptance criteria for structures, systems, components, 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, NPPD will perform a probabilistic risk evaluation using the guidance contained in NRC approved NEI 04-10, Revision 1, in accordance with the TS SFCP. 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 1.177.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based upon the reasoning presented above, NPPD concludes that the requested change does not involve a significant hazards consideration as set forth in 10 CFR 50.92(c), Issuance of Amendment.