Charles R. Pierce
Regulatory Affairs Director

Southern Nuclear Operating Company, Inc.
40 Inverness Center Parkway
Post Office Box 1295
Birmingham, Alabama 35201

Tel 205.992.7872
Fax 205.992.7601

SOUTHERN COMPANY

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50-366

NL-14-1095

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

Edwin I. Hatch Nuclear Plant
Request for Technical Specification Amendment
Adoption of Previously Approved Generic Technical Specification Changes and Other Changes

Ladies and Gentlemen:

In accordance with the provisions of 10 CFR 50.90, Southern Nuclear Operating Company (SNC) is submitting a request for an amendment to the Technical Specifications (TS) for Edwin I. Hatch Nuclear Plant (HNP), Units 1 and 2.

The proposed amendment adopts several previously NRC-approved Technical Specifications Task Force (TSTF) Travelers. TSTF Travelers are generic changes to the Improved Standard Technical Specifications. The requested amendment also adopts two TSTF Travelers that were not submitted to the NRC for generic review and approval. These Travelers, called T-Travelers, underwent nuclear industry review and were approved by the TSTF as templates for plant-specific amendments. The industry review process ensures that T-Travelers meet the same ISTS format and usage rules as Travelers that are submitted for generic approval by NRC.

Additionally, the requested amendment will also adopt one feature of the Improved Standard Technical Specifications that is not associated with a Traveler.

These changes were chosen to increase the consistency between the HNP Technical Specifications, the Improved Standard Technical Specifications, and the Technical Specifications of other plants in the SNC fleet. A complete list of the requested changes is located in Enclosure 1.

Enclosure 1 provides the basis for the proposed TS changes. Enclosure 2 provides marked-up Technical Specification pages. Enclosure 3 contains example Bases changes that complement the proposed Technical Specification changes. The proposed Bases changes are provided for information only. The Bases will be revised under the Technical Specification Bases Control Program following NRC approval of the proposed Technical Specification changes. Enclosure 4 provides the clean-typed Technical Specification pages. Enclosure 5

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provides copies of the TSTF T-Travelers. Enclosure 6 provides a summary of the regulatory commitments made in this license amendment request.

SNC requests approval of the proposed license amendment by October 9, 2014, with the amendment being implemented within 90 days of issuance of the amendment.

In accordance with 10 CFR 50.91(b)(1), "State Consultation," a copy of the this letter and its reasoned analysis of no significant hazards consideration is being provided to the designated State of Georgia officials.

The NRC commitments contained in this letter are provided as a table in Attachment 6. If you have any questions, please contact Ken McElroy at (205) 992-7369.

Mr. C. R. Pierce states he is Regulatory Affairs Director of Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company and to the best of his knowledge and belief, the facts set forth in this letter are true.

Respectfully submitted,

C. R. Pierce

C. R. Pierce
Regulatory Affairs Director

CRP/RMJ

Sworn to and subscribed before me this 10 *day of* October, *2014.*

Tamra L. Crayton
Notary Public

My commission expires: 10-8-2017

Enclosures:
1. Basis for Proposed Changes
2. HNP Technical Specifications Marked-Up Pages
3. HNP Technical Specifications Bases Marked-Up Pages
4. HNP Technical Specifications Clean-Typed Pages
5. Copies of TSTF T-Travelers
6. Summary of Regulatory Commitments

cc: Southern Nuclear Operating Company
Mr. S. E. Kuczynski, Chairman, President & CEO
Mr. D. G. Bost, Executive Vice President & Chief Nuclear Officer
Mr. D. R. Vineyard, Vice President – Hatch
Mr. B. L. Ivey, Vice President – Regulatory Affairs
Mr. D. R. Madison, Vice President – Fleet Operations
Mr. B. J. Adams, Vice President – Engineering
Mr. G. L. Johnson, Regulatory Affairs Manager - Hatch
RType: CHA02.004

U. S. Nuclear Regulatory Commission
Mr. V. M. McCree, Regional Administrator
Mr. R. E. Martin, NRR Senior Project Manager – Hatch
Mr. D. H. Hardage, Senior Resident Inspector – Hatch

State of Georgia
Mr. J. H. Turner, Environmental Director Protection Division

Edwin I. Hatch Nuclear Plant
Request for Technical Specifications Amendment
Adoption of Generic Technical Specification Changes

Enclosure 1

Basis for Proposed Changes

Basis for the Proposed Changes

1.0 Description

The requested amendment adopts several previously NRC-approved Technical Specifications Task Force (TSTF) Travelers. TSTF Travelers are generic changes to the Improved Standard Technical Specifications (ISTS). The requested amendment also adopts two TSTF T-Travelers. These T-Travelers, underwent nuclear industry review and were approved by the TSTF as templates for plant-specific amendments. However, they were not submitted to the NRC for generic review and approval. The industry review process ensures that T-Travelers meet the same ISTS format and usage rules as Travelers that are submitted for generic approval by NRC. The requested amendment will also adopt one feature of the Improved Standard Technical Specifications not associated with a Traveler.

These changes were chosen to increase the consistency between the HNP Technical Specifications, the Improved ISTS for BWR/4 plants (NUREG-1433), and the Technical Specifications of the other plants in the SNC fleet.

The requested Travelers are:

1. TSTF-30-A, Revision 3, "Extend the Completion Time for Inoperable Isolation Valve to a Closed System to 72 hours" (Page E1-5)

2. TSTF-45-A, Revision 2, "Exempt Verification of CIVs that are Not Locked, Sealed or Otherwise Secured" (Page E1-10)

3. TSTF-46-A, Revision 1, "Clarify the CIV Surveillance to Apply Only to Automatic Isolation Valves" (Page E1-14)

4. TSTF-222-A, Revision 1, "Control Rod Scram Time Testing" (Page E1-18)

5. TSTF-264-A, Revision 0, "3.3.9 and 3.3.10 - Delete Flux Monitors Specific Overlap Requirement SRs" (Page E1-22)

6. TSTF-269-A, Revision 2, "Allow Administrative Means of Position Verification for Locked or Sealed Valves" (Page E1-25)

7. TSTF-273-A, Revision 2, "Safety Function Determination Program Clarifications" (Page E1-29)

8. TSTF-283-A, Revision 3, "Modify Section 3.8 Mode Restriction Notes" (Page E1-32)

9. TSTF-284-A, Revision 3, "Add 'Met vs. Perform' to Technical Specification 1.4, Frequency" (Page E1-39)

10. TSTF-295-A, Revision 0, "Modify Note 2 to Actions of PAM Table to Allow Separate Condition Entry for Each Penetration" (Page E1-42)

11. TSTF-306-A, Revision 2, "Add Action to LCO 3.3.6.1 to Give Option to Isolate the Penetration" (Page E1-46)

12. TSTF-308-A, Revision 1, "Determination of Cumulative and Projected Dose Contributions in RECP" (Page E1-52)

13. TSTF-318-A, Revision 0, "Revise 3.5.1 for One LPCI Pump Inoperable in Each of Two ECCS Divisions" (Page E1-55)

14. TSTF-322-A, Revision 2, "Secondary Containment and Shield Building Boundary Integrity SRs" (Page E1-59)

15. TSTF-323-A, Revision 0, "EFCV Completion Time to 72 hours" (Page E1-63)

16. TSTF-374-A, Revision 0, "Revision to TS 5.5.13 and Associated TS Bases for Diesel Fuel Oil" (Page E1-68)

17. TSTF-400-A, Revision 1, "Clarify SR on Bypass of DG Automatic Trips" (Page E1-73)

18. TSTF-439-A, Revision 2, "Eliminate Second Completion Times Limiting Time from Discovery of Failure to Meet An LCO" (Page E1-77)

The requested T-Travelers are listed below. Copies of the T-Travelers are included as Enclosure 5.

19. TSTF-458-T, Revision 0, "Removing Restart of Shutdown Clock for Increasing Suppression Pool Temperature" (Page E1-82)

20. TSTF-464-T, Revision 0, "Clarify the Control Rod Block Instrumentation Required Action" (Page E1-85)

In addition, SNC is requesting one change that reflects ISTS requirements which were not added by a Traveler.

21. ISTS Adoption #1 - Revise the 5.5.7 Introductory Paragraph to be Consistent with the ISTS (Page E1-88)

2.0 Proposed Changes, Justifications, and No Significant Hazards Determinations

Each Traveler, and the ISTS adoption, are discussed in an individual analysis provided in Section 2.1 through 2.21. Each section contains the following topics:

Description of Proposed Change - This topic describes the effect of adopting the subject Traveler on the Hatch Technical Specifications.

Differences Between the Proposed Change and the Approved Traveler - This topic describes differences between the changes proposed to the Hatch Technical Specifications and the ISTS mark-ups provided in the approved Traveler.

Summary of the Approved Traveler Justification - This topic summarizes the justification utilized by the NRC when approving the Traveler.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification - This topic describes any differences between the Traveler justification utilized by the NRC when approving the Traveler and the justification for adopting the Traveler in the Hatch Technical Specifications.

License Commitments Required to Adopt this Change - Some Travelers require that licensees to make regulatory commitments as a condition of adopting the change. This topic describes any such commitments being made by SNC as part of this request.

NRC Approval - This topic references the NRC letter, if any, approving the Traveler. It also provides example NRC approvals of plant-specific requests to adopt the Traveler. If the documents are in the NRC ADAMS system, the accession number (ACN) is given.

List of Affected Pages - This topic lists the Hatch Technical Specification and Technical Specification Bases pages affected by the adoption of this Traveler.

Applicable Regulatory Requirements/Criteria - This topic describes how the justification satisfies the applicable regulatory requirements and criteria and provides a basis that the NRC staff may use to find the proposed amendment acceptable.

In some cases, a Traveler or model Safety Evaluation may discuss the applicable regulatory requirements and guidance, and include references to the 10 CFR 50, Appendix A, General Design Criteria (GDC). Although Hatch Unit 2 was licensed to the requirements of 10 CFR 50, Appendix A, GDC, Hatch Unit 1 was not. The Hatch Unit 1 construction permit was received under the 70 general criteria identified in 32 FR 10213, published July 11, 1967 (ML043310029). In those cases where the 10 CFR 50, Appendix A, GDC are discussed, an evaluation of the relevant 1967 general design criterion is also provided.

Significant Hazards Consideration - This topic provides an evaluation of whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment."

The one proposed change that is not associated with a Traveler (ISTS Adoption #1) is discussed in an individual analysis provided in Section 2.22. This section contains topics analogous to those in Sections 2.1 through 2.21, with the exception that the NRC's approval of the ISTS requirement in the Vogtle ISTS conversion is used as the basis.

The affected marked-up Technical Specifications pages are in Enclosure 2. Retyped Technical Specification pages are in Enclosure 4.

Example mark-ups of the affected Technical Specification Bases pages are included for information only in Enclosure 3. The Bases will be revised under the Technical Specification Bases Control Program following NRC approval of the proposed Technical Specification changes.

To facilitate NRC review, each section will begin on a new page.

2.1 TSTF-30-A, Revision 3, "Extend the Completion Time for Inoperable Isolation Valve to a Closed System to 72 Hours"

Description of Proposed Change
Specification 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Action C, is revised to provide a 72 hour Completion Time for penetration flow paths with one inoperable PCIV with a closed system.

Differences Between the Proposed Change and the Approved Traveler
The Hatch Technical Specifications differ from the ISTS in that the Hatch Technical Specifications provide a separate Action (Condition D) for penetration flow paths with leakage not within limit with a Completion Time of 4 hours. As a result, a penetration flow path with an inoperable PCIV due to leakage not within limit will continue to have a 4 hour Completion Time instead of the 72 hour Completion Time provided in TSTF-30-A.

TSTF-30-A adds Generic Issue B-24 as a Reference in the Bases for TS 36.1.3. Generic Issue B-24 is not applicable for HNP Units 1 and 2, and this change is therefore not adopted.

Additional text is added to the Bases for TS 3.6.1.3, Condition C, describing the 4 hour Completion Time for inoperable PCIVs in penetrations with a closed system and excess flow check valves (EFCVs).

Summary of the Approved Traveler Justification
Currently, Specification 3.6.1.3 does not allow the use of a closed system to isolate a failed containment isolation valve even though the closed system is subjected to a Type A containment leakage test, is missile protected, and seismic category I piping. A closed system also typically has flow through it during normal operation such that any loss of integrity could be continually observed through leakage detection system within containment and system walk downs for closed systems outside containment. Therefore, Required Action C.1 is revised to allow 72 hours to isolate an inoperable PCIV associated with a closed system. This 72 hour period provides the necessary time to perform repairs on a failed containment isolation valve when relying on an intact closed system. A Completion Time of 72 hours is considered appropriate given that certain valves may be located inside containment, the reliability of the closed system, and that 72 hours is typically provided for losing one train of redundancy throughout the ISTS.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
The extension of the Completion Time from 12 hours to 72 hours for an EFCV line with an inoperable PCIV is discussed in the adoption of TSTF-323-A (Section 2.15).

Licensee Commitments Required to Adopt this Change
None

NRC Approval

The NRC documented their approval of TSTF-30-A, Revision 3 in a letter from William Beckner (NRC) to James Davis (NEI) dated August 16, 1999 (ACN ML9908250220). TSTF-30-A, Revision 3 has been adopted by many plants as part of complete conversion to the ISTS, such as Arkansas Nuclear One, Unit 1 (ACN ML013050554). An example of a plant-specific NRC approval of the changes in TSTF-30-A is Peach Bottom Units 2 and 3 Amendment Numbers 259/262, dated May 10, 2006 (ACN ML061070292).

List of Affected Pages

Unit 1

3.6-9
B3.6-20
B3.6-26

Unit 2

3.6-9
B3.6-20
B3.6-27

Applicable Regulatory Requirements/Criteria

Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criteria:

Criterion 54, Piping Systems Penetrating Containment, states:

> Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to periodically test the operability of isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Criterion 55, Reactor Coolant Pressure Boundary Penetrating Containment, states:

> Each line that is part of the RCPB and penetrates the primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, e.g., instrument lines, are acceptable on some other defined basis:
>
> (1) One locked-closed isolation valve inside and one locked-closed isolation valve outside containment.
>
> (2) One automatic valve inside and one locked-closed isolation valve outside containment.
>
> (3) One locked closed isolation valve inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

(4) One automatic isolation valve in inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Criterion 56, Primary Containment Isolation, states:
Each line connecting directly to the containment atmosphere and penetrating the primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, e.g., instrument lines, are acceptable on some other defined basis:

(1) One locked-closed isolation valve inside and one locked-closed isolation valve outside containment.

(2) One automatic valve inside and one locked-closed isolation valve outside containment.

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

(4) One automatic isolation valve in inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Criterion 57, Closed System Isolation Valves, states:
Each line penetrating the primary reactor containment that is neither part of the RCPB nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, locked-closed, or capable of remote-manual operation. This

valve shall be located outside and as close to the containment as practical.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 51, Reactor Coolant Pressure Boundary Outside Containment, states:

If part of the reactor coolant pressure boundary is outside the containment, appropriate features an necessary shall be provided to protect the health and safety of the public in case of an accidental rupture in that part. Determination of the appropriateness of features such as isolation valves and additional containment shall include consideration of the environmental and population conditions surrounding the site.

1967 GDC Criterion 53, Containment Isolation Valves, states:

Penetrations that require closure for the containment function shall be protected by redundant valving and associated apparatus.

1967 GDC Criterion 56, Provisions for Testing of Penetrations, states:

Penetrations shall be made for testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at design pressure at any time.

1967 GDC Criterion 57, Provisions for Testing of Isolation Valves, states:

Capability shall be provided for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits.

These criteria specify the number, type, and positions of CIVs required for containment piping penetrations. However, these criteria do not contain provisions describing actions to take if containment isolation valves become inoperable during plant operation.

The regulations in 10 CFR 50.36, "Technical Specifications," provide general requirements for the establishment of Technical Specifications, including limiting conditions for operation, action requirements, and Surveillance Requirements, but do not provide specific guidance on Actions and Completion Times when a limiting condition for operation is not met.

The best guidance is that contained in the ISTS, NUREG-1433. The proposed Completion Time is consistent with the NUREG-1433 Completion Time.

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

Significant Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change extends the Completion Time to isolate an inoperable primary containment isolation valve (PCIV) from 4 hours to 72 hours when the PCIV is associated with a closed system. The PCIVs are not an initiator of any accident previously evaluated. The consequences of a previously evaluated accident during the extended Completion Time are the same as the consequences during the existing Completion Time. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change extends the Completion Time to isolate an inoperable primary containment isolation valve (PCIV) from 4 hours to 72 hours when the PCIV is associated with a closed system. The PCIVs serve to mitigate the potential for radioactive release from the primary containment following an accident. The design and response of the PCIVs to an accident are not affected by this change. The revised Completion Time is appropriate given the isolation capability of the closed system. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.2 TSTF-45-A, Revision 2, "Exempt Verification of CIVs that are Locked, Sealed or Otherwise Secured"

Description of Proposed Change
The proposed change revises SRs 3.6.1.3.2 and 3.6.1.3.3 in Specification 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," to exempt manual PCIVs and blind flanges which are locked, sealed, or otherwise secured in position from position verification requirements. The proposed change also revises SR 3.6.4.2.1 in Specification 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," to exempt manual SCIVs and blind flanges which are locked, sealed, or otherwise secured in position from position verification requirements.

Differences Between the Proposed Change and the Approved Traveler
None

Summary of the Approved Traveler Justification
The proposed change revises SRs 3.6.1.3.2, and 3.6.1.3.3, for manual PCIVs and blind flanges located inside and outside containment, and SR 3.6.4.2 for manual SCIVS and blind flanges, by adding a provision to exempt these valves and devices from the position verification requirements if they are locked, sealed, or otherwise secured in position. The intent of these SRs is to ensure the position of valves that could be inadvertently repositioned. It is not necessary to check the position of manual PCIVs, SCIVs, and blind flanges that are locked, sealed, or otherwise secured, because these valves and devices are verified to be in the correct position upon being locked, sealed, or otherwise secured and any changes to their position is performed under administrative controls.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

The proposed change is consistent with other Hatch Surveillance Requirements that require verification valve position, such as SR 3.1.7.6 (Standby Liquid Control System valves), SRs 3.5.1.2 and 3.5.2.4 (Emergency Core Cooling System valves), SR 3.5.3.2 (Reactor Core Isolation Cooling System valves), SR 3.6.2.3.1 (Residual Heat Removal [RHR] Suppression Pool Cooling valves), SR 3.6.2.4.1 (RHR Suppression Pool Spray valves), SR 3.6.2.5.1 (RHR Drywell Spray valves), SR 3.6.3.1.2 (Containment Atmosphere Dilution System valves), SR 3.7.1.1 (RHR Service Water System valves), SR 3.7.2.2 (Plant Service Water System valves), SR 3.7.3.1 (Diesel Generator Standby Service Water System valves).

Licensee Commitments Required to Adopt this Change
None

NRC Approval
TSTF-45-A, Revision 2, was approved by the NRC as documented in a letter from William Beckner (NRC) to James Davis (NEI), dated July 26, 1999 (ACN ML9907300113). TSTF-46-A, Revision 2 has been adopted by many plants as part of complete conversion to the ISTS, such as North Anna Power Station (ACN ML021200265). An example of a plant-specific NRC approval of

the changes in TSTF-45-A, Revision 1 is Columbia Generating Station, Amendment Number 208, dated September 15, 2008 (ACN ML081900507).

List of Affected Pages
Unit 1
3.6-11
3.6-39
B3.6-22
B3.6-23
B3.6-85

Unit 2
3.6-11
3.6-38
B3.6-22
B3.6-23
B3.6-86

Applicable Regulatory Requirements/Criteria
Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criteria:

Criterion 16, Containment Design, states:
Reactor containment and associated systems shall be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

Criterion 53, Provisions for Containment Testing and Inspection, states:
The reactor containment shall be designed to permit (1) appropriate periodic inspection of all important area, such as penetrations, (2) an appropriate surveillance program, and (3) periodic testing at containment design pressure of the leak-tightness of penetrations which have resilient seals and expansion bellows.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 49, Containment Design Basis, states:
The containment structure, including access openings and penetrations, and any necessary containment heat removal systems shall be designed so that the containment structure can accommodate without exceeding the design leakage rate the pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

1967 GDC Criterion 55, Containment Periodic Leakage Rate Testing, states:

The containment shall be designed so that integrated leakage rate testing can be done periodically at deign pressure during plant lifetime.

1967 GDC Criterion 56, Provisions for Testing of Penetrations, states: Penetrations shall be made for testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at design pressure at any time.

1967 GDC Criterion 57, Provisions for Testing of Isolation Valves, states: Capability shall be provided for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits.

The regulations do not specify how frequently or in what manner systems and components are to be tested or verified. The proposed Surveillance Requirements are consistent with NUREG-1433.

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

Signification Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change exempts manual primary containment isolation valves and blind flanges located inside and outside of containment, and manual secondary containment isolation valves and blind flanges, that are locked, sealed, or otherwise secured in position from the periodic verification of valve position required by Surveillance Requirements 3.6.1.3.2, 3.6.1.3.3, and 3.6.4.2.1. The exempted valves and devices are verified to be in the correct position upon being locked, sealed, or secured. Because the valves and devices are in the condition assumed in the accident analysis, the proposed change will not affect the initiators or mitigation of any accident previously evaluated. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

Response: No.

The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

Response: No.

The proposed change exempts manual primary containment isolation valves and blind flanges located inside and outside of containment, and manual secondary containment isolation valves and blind flanges, that are locked, sealed, or otherwise secured in position from the periodic verification of valve position required by Surveillance Requirements 3.6.1.3.2, 3.6.1.3.3, and 3.6.4.2.1. These valves and devices are administratively controlled and their operation is a non-routine event. The position of a locked, sealed or secured blind flange or valve is verified at the time it is locked, sealed or secured, and any changes to their position is performed under administrative controls. Industry experience has shown that these valves are generally found to be in the correct position. Since the change impacts only the frequency of verification for blind flange and valve position, the proposed change will provide a similar level of assurance of correct position as the current frequency of verification. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.3 TSTF-46-A, Revision 1, "Clarify the CIV Surveillance to Apply Only to Automatic Isolation Valves"

Description of Proposed Change
The proposed change modifies SR 3.6.1.3.5 in Specification 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," and SR 3.6.4.2.2, in Specification 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," including their associated Bases, to delete the requirement to verify the isolation time of "each power operated" containment isolation valve and only require verification of each "power operated automatic isolation valve."

Differences Between the Proposed Change and the Approved Traveler
The numbering of SRs in HNP TS 3.6.1.3 is different from the ISTS numbering. HNP SR 3.6.1.3.5, is equivalent to SR 3.6.1.3.6 in the ISTS. This has no effect on the requested change.

Summary of the Approved Traveler Justification
SRs 3.6.1.3.5 and 3.6.4.2.2 require verification that the isolation time of each power operated and each automatic PCIV and SCIV is within limits. The Bases for these SRs state that these isolation time tests ensure that the valves will isolate in a time period less than or equal to that assumed in the safety analysis. However, there are some valves credited as containment isolation valves that are power operated (i.e., can be remotely operated) that do not receive a containment isolation signal. These power operated valves do not have an isolation time that is assumed in the accident analyses since they require operator action. The revised SRs clarify that it is only PCIVs and SCIVs that receive an automatic isolation signal that are in the scope of the SRs. The associated Technical Specification Bases are also revised to reflect these changes. Deleting the reference to "power operated" isolation valve time testing reduces the potential for misinterpreting the requirements of SRs 3.6.1.3.5 and 3.6.4.2.2 while maintaining the assumptions of the accident analysis.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
The NRC did not issue a letter approving TSTF-46-A, Revision 1; however, it was incorporated by the NRC into Revision 2 of the ISTS NUREGs. TSTF-46-A, Revision 1 has been adopted by many plants as part of complete conversion to the ISTS, such as North Anna Power Station (ACN ML021200265). An example of a plant-specific NRC approval of the changes in TSTF-45-A, Revision 1 is Columbia Generating Station, Amendment Number 208, dated September 15, 2008 (ACN ML081900507).

List of Affected Pages
Unit 1
3.6-11
3.6-39
B3.6-23
B3.6-82
B3.6-86

Unit 2
3.6-11
3.6-38
B3.6-23
B3.6-83
B3.6-87

Applicable Regulatory Requirements/Criteria
Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criteria:

Criterion 16, Containment Design, states:
> Reactor containment and associated systems shall be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 49, Containment Design Basis, states:
> The containment structure, including access openings and penetrations, and any necessary containment heat removal systems shall be designed so that the containment structure can accommodate without exceeding the design leakage rate the pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

Title 10 of the Code of Federal Regulations (10 CFR), Part 50, 10 CFR 50.36(c)(2)(ii)(C), states:
> *Criterion 3.* A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

The change affects power operated PCIVs and SCIVs that do not receive a containment isolation signal, and that do not have an isolation time that is assumed in the accident analyses, since they require operator action. There is no regulatory requirement to establish or verify isolation times for PCIVs and SCIVs that are not credited to automatically close in the accident analysis. The

changes will not alter the PCIV or SCIVs design or the design of the isolation logic or circuitry. The PCIVs and SCIVs will continue to comply with all applicable regulatory requirements. The proposed Surveillance Requirements are consistent with NUREG-1433.

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

Signification Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change revises the requirements in Technical Specification Surveillance Requirements (SRs) 3.6.1.3.5 and 3.6.4.2.2, and their associated Bases, to delete the requirement to verify the isolation time of "each power operated" PCIV and SCIV and only require verification of closure time for each "automatic power operated isolation valve." The closure times for PCIVs and SCIVs that do not receive an automatic closure signal are not an initiator of any design basis accident or event, and therefore the proposed change does not increase the probability of any accident previously evaluated. The PCIVs and SCIVs are used to respond to accidents previously evaluated. Power operated PCIVs and SCIVs that do not receive an automatic closure signal are not assumed to close in a specified time. The proposed change does not change how the plant would mitigate an accident previously evaluated. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

   Response: No.

   The proposed change does not result in a change in the manner in which the PCIVs and SCIVs provide plant protection or introduce any new or different operational conditions. Periodic verification that the closure times for PCIVs and SCIVs that receive an automatic closure signal are within the limits established by the accident analysis will continue to be performed under SRs 3.6.1.3.5 and 3.6.4.2.2. The change does not alter assumptions made in the safety analysis, and is consistent with the safety analysis assumptions and current plant operating practice. There are also

no design changes associated with the proposed changes, and the change does not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed). Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change provides clarification that only PCIVs and SCIVs that receive an automatic isolation signal are within the scope of SRs 3.6.1.3.5 and 3.6.4.2.2. The proposed change does not result in a change in the manner in which the PCIVs and SCIVs provide plant protection. Periodic verification that closure times for PCIVs and SCIVs that receive an automatic isolation signal are within the limits established by the accident analysis will continue to be performed. The proposed change does not affect the safety analysis acceptance criteria for any analyzed event, nor is there a change to any safety analysis limit. The proposed change does not alter the manner in which safety limits, limiting safety system settings or limiting conditions for operation are determined, nor is there any adverse effect on those plant systems necessary to assure the accomplishment of protection functions. The proposed change will not result in plant operation in a configuration outside the design basis. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.4 TSTF-222-A, Revision 1, "Control Rod Scram Time Testing"

Description of Proposed Change
Specification 3.1.4, "Control Rod Scram Times," SRs 3.1.4.1 and 3.1.4.4, are revised to only require scram time testing of control rods that are in an affected core cell. The SR 3.1.4.1 Frequency "Prior to exceeding 40% RTP after fuel movement within the reactor vessel," is eliminated and a new Frequency is added to SR 3.1.4.4 which states, "Prior to exceeding 40% RTP after fuel movement within the affected core cell."

Differences Between the Proposed Change and the Approved Traveler
None

Summary of the Approved Traveler Justification
Surveillance 3.1.4.1 requires each control rod scram time to be verified when any fuel movement within the reactor vessel (RPV) occurs. This requires all control rod scram times must be determined, even if only one bundle is moved (e.g., replacing a leaking fuel bundle mid-cycle). The Bases were generically revised during the development of Revision 1 of the ISTS NUREGs (BWR-18, Comments C.2 and C.14) to address this situation by adding the following statement to the SR 3.1.4.1 Bases, "In the event fuel movement is limited to selected core cells, it is the intent of this SR that only those CRDs associated with the core cells affected by the fuel movements are required to be scram time tested." However, the Surveillance was not modified and continues to require each rod to be tested. SR 3.1.4.4 requires verification of each "affected" control rod scram time testing instead of all control rod scram times as required by SR 3.1.4.1. Therefore, the first Frequency of SR 3.1.4.1 is eliminated and a similar Frequency is added to SR 3.1.4.4. SR 3.1.4.4 will require testing "Prior to exceeding 40% RTP after fuel movement within the affected core cell." The Bases of SR 3.1.4.4 will state that it is expected that during a routine refueling outage, all control rods will be affected. Thus, the requirement to test all the control rods remains unchanged. This change is acceptable because it only clarifies the intent of the existing requirements and does not reduce the testing currently required for demonstrating control rod operability.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
The NRC documented their approval of TSTF-222-A, Revision 1 in a letter from William Beckner (NRC) to James Davis (NEI) dated May 12, 1999 (ACN 9905180104). An example of a plant-specific NRC approval of the changes in TSTF-222-A is River Bend Station, Unit 1, Amendment Number 165, dated August 11, 2009 (ACN ML092010370).

List of Affected Pages
Unit 1
3.1-10
B3.1-22
B3.1-23

Unit 2
3.1-10
B3.1-22
B3.1-23
B3.1-24

Applicable Regulatory Requirements/Criteria
Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criterion:

Criterion 26, Reactivity Control System Redundancy and Capability, states:
Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 27, Redundancy of Reactivity Control, states:
At least two independent reactivity control systems, preferably of different principles, shall be provided.

The regulations in 10 CFR 50.36(c)(3), "Surveillance Requirements," state:
Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

The proposed changes do not affect the design of the reactivity control system and continues to test components to ensure that the necessary quality is maintained. The proposed Surveillance Requirements are consistent with NUREG-1433.

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be

conducted in compliance with the Commission's regulations, and (3) the approval of the proposed change will not be inimical to the common defense and security or to the health and safety of the public.

Significant Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change clarifies the intent of Surveillance testing in Specification 3.1.4, "Control Rod Scram Times." The existing Specification wording requires control rod scram time testing of all control rods whenever fuel is moved within the reactor pressure vessel, even though the Technical Specification Bases state that control rod scram time testing is only required in the affected core cells. The Frequency of Surveillances 3.1.4.1 and 3.1.4.4 are revised to implement the Bases statement in the Specifications. The proposed change does not affect any plant equipment, test methods, or plant operation, and are not initiators of any analyzed accident sequence. The control rods will continue to perform their function as designed. Operation in accordance with the proposed Technical Specifications will ensure that all analyzed accidents will continue to be mitigated as previously analyzed. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change clarifies the intent of Surveillance testing in Specification 3.1.4, "Control Rod Scram Times." The existing Specification wording requires control rod scram time testing of all control rods whenever fuel is moved within the reactor pressure vessel, even

though the Technical Specification Bases state that control rod scram time testing is only required in the affected core cells. The proposed change will not affect the operation of plant equipment or the function of any equipment assumed in the accident analysis. Control rod scram time testing will be performed following any fuel movement that could affect the scram time. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.5 TSTF-264-A, Revision 0, "3.3.9 and 3.3.10 - Delete Flux Monitors Specific Overlap Requirement SRs"

Description of Proposed Change
The proposed change revises Specification 3.3.1.1, "RPS Instrumentation," by deleting Surveillances 3.3.1.1.6 and 3.3.1.1.7, which verify the overlap between the source range monitor (SRM) and the intermediate range monitor (IRM), and between the IRM and the average power range monitor (APRM).

Differences Between the Proposed Change and the Approved Traveler
TSTF-264-A revised the ISTS NUREG. As such, SR 3.3.1.1.6 and SR 3.3.1.1.7 were deleted, all subsequent surveillances were renumbered, and all references to the renumbered surveillances were revised. While this is appropriate for a generic standard document, renumbering a large number of surveillances in the plant-specific technical specifications would result in a prohibitive number of revisions to procedures and training materials. Therefore, in the proposed change, the deleted Surveillances are marked "(Not used.)" and the subsequent Surveillances are not renumbered.

Summary of the Approved Traveler Justification
Specification 3.3.1.1, "RPS Instrumentation," Surveillances 3.3.1.1.6 and 3.3.1.1.7, require verification of one decade of overlap for the SRM and IRM indications and for the IRM and APRM indications. These surveillances are unnecessary because their testing requirements are being incorporated into the requirements of the Channel Check required by SR 3.3.1.1.1. Further, failure of the surveillance requires that both monitors being tested be considered inoperable even if the lack of overlap is due to only one monitor. This is unnecessary.

The Channel Check Surveillance requires the channel to meet the established "agreement criteria." In this case, the Channel Check agreement criterion can be established to provide this requirement with appropriate flexibility to determine if components are inoperable and to initiate the appropriate actions. This change is consistent with source range, intermediate range, and power range neutron flux instrumentation ISTS requirements for Westinghouse and Combustion Engineering plants, neither of which include specific surveillances to verify overlap requirements.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
The NRC documented their approval of TSTF-264-A, Revision 0, in a letter from William Beckner (NRC) to James Davis (NEI) dated July 26, 1999 (ACN 9907300113). An example of a plant-specific NRC approval of the changes in TSTF-264-A is Grand Gulf Unit 1 Amendment Number 169, dated February 1, 2006 (ACN ML060520052).

List of Affected Pages
Unit 1
3.3-4
3.3-5
3.3-7
B3.3-24
B3.3-25
B3.3-26
B3.3-33
B3.3-35

Unit 2
3.3-4
3.3-5
3.3-7
B3.3-24
B3.3-25
B3.3-26
B3.3-33
B3.3-35

Applicable Regulatory Requirements/Criteria
Title 10 of the Code of Federal Regulations (10 CFR), Part 50, paragraph 36(c)(3), "Surveillance Requirements," states:

> Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

The proposed change continues to test components to ensure that the necessary quality is maintained. The proposed Surveillance Requirements are consistent with NUREG-1433.

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

Significant Hazards Consideration
SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

The proposed change eliminates two Surveillances Requirements (SRs) (SRs 3.3.1.1.6 and 3.3.1.1.7) which verify the overlap between the source range monitor (SRM) and intermediate range monitor (IRM) and between the IRM and the average power range monitor (APRM). The testing requirement is incorporated in the existing Channel Check Surveillance (SR 3.3.1.1.1). The proposed change does not affect any plant equipment, test methods, or plant operation, and are not initiators of any analyzed accident sequence. The SRM, IRM, and APRM will continue to perform their function as designed. Operation in accordance with the proposed Technical Specifications will ensure that all analyzed accidents will continue to be mitigated as previously analyzed. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change eliminates SRs 3.3.1.1.6 and 3.3.1.1.7 which verify the overlap between the SRM and IRM and between the IRM and the APRM. The testing requirement is incorporated in the existing Channel Check Surveillance (SR 3.3.1.1.1). The proposed change will not affect the operation of plant equipment or the function of any equipment assumed in the accident analysis. Instrument channel overlap will continue to be verified under the existing Channel Check surveillance. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.6 TSTF-269-A, Revision 2, "Allow Administrative Means of Position Verification for Locked or Sealed Valves"

Description of Proposed Change
The proposed change modifies Specification 3.6.1.3, "Primary Containment Isolation Valves," and Specification 3.6.4.2, "Secondary Containment Isolation Valves." The specifications require penetrations with an inoperable isolation valve to be isolated and periodically verified to be isolated. A Note is added to Specification 3.6.1.3, Actions A and C, and Specification 3.6.4.2, Action A, to allow isolation devices that are locked, sealed, or otherwise secured to be verified by use of administrative means.

Differences Between the Proposed Change and the Approved Traveler
TSTF-269-A also modified Specification 3.6.1.3, Action E, which is optional in the ISTS NUREG. The equivalent of Action E does not appear in the Hatch Technical Specifications.

Summary of the Approved Traveler Justification
The purpose of the periodic verification that a penetration with an inoperable isolation valve continues to be isolated is to detect and correct inadvertent repositioning of the isolation device. However, the function of locking, sealing, or securing an isolation device is to ensure that the device is not inadvertently repositioned. Therefore, it is sufficient to assume that the initial establishment of component status (e.g., isolation valves closed) was performed correctly and subsequent periodic re-verification need only be a verification of the administrative control that ensures that the component remains in the required state. It is unnecessary and undesirable to remove the lock, seal, or other means of securing the component solely to perform an active verification of the required state as it would increase the chance of mispositioning due to the frequent manipulation.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
The NRC documented their approval of TSTF-269-A, Revision 2, in a letter from William Beckner (NRC) to James Davis (NEI) dated July 16, 1998 (ACN 9807280010). An example of a plant-specific NRC approval of the changes in TSTF-269-A is Peach Bottom Atomic Power Station Units 2 and 3 Amendment Numbers 259/262 dated May 10, 2006 (ACN ML061070292).

List of Affected Pages
Unit 1
3.6-8
3.6-9
3.6-37
B3.6-18

B3.6-20
B3.6-84

Unit 2
3.6-8
3.6-9
3.6-36
B3.6-18
B3.6-20
B3.6-85

Applicable Regulatory Requirements/Criteria
Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criteria:

Criterion 16, Containment Design, states:
Reactor containment and associated systems shall be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

Criterion 53, Provisions for Containment Testing and Inspection, states:
The reactor containment shall be designed to permit (1) appropriate periodic inspection of all important area, such as penetrations, (2) an appropriate surveillance program, and (3) periodic testing at containment design pressure of the leak-tightness of penetrations which have resilient seals and expansion bellows.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 49, Containment Design Basis, states:
The containment structure, including access openings and penetrations, and any necessary containment heat removal systems shall be designed so that the containment structure can accommodate without exceeding the design leakage rate the pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

1967 GDC Criterion 55, Containment Periodic Leakage Rate Testing, states:
The containment shall be designed so that integrated leakage rate testing can be done periodically at deign pressure during plant lifetime.

1967 GDC Criterion 56, Provisions for Testing of Penetrations, states:
Penetrations shall be made for testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at design pressure at any time.

1967 GDC Criterion 57, Provisions for Testing of Isolation Valves, states:
Capability shall be provided for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits.

The requirements of 10 CFR 50.36(c)(3), "Surveillance Requirements," state:
Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

The regulations do not specify how frequently or in what manner systems and components are to be tested. The proposed changes are consistent with NUREG-1433.

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

Significant Hazards Consideration
SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change modifies Specification 3.6.1.3, "Primary Containment Isolation Valves," and Specification 3.6.4.2, "Secondary Containment Isolation Valves." The specifications require penetrations with an inoperable isolation valve to be isolated and periodically verified to be isolated. A Note is added to Specification 3.6.1.3, Actions A and C, and Specification 3.6.4.2, Action A, to allow isolation devices that are locked, sealed, or otherwise secured to be verified by use of administrative means. The proposed change does not affect any plant equipment, test methods, or plant operation, and are not initiators of any analyzed accident sequence. The inoperable containment penetrations will continue to be isolated, and hence perform their isolation function. Operation in accordance with the proposed Technical Specifications will ensure that all analyzed accidents will continue to be mitigated as previously analyzed. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change will not affect the operation of plant equipment or the function of any equipment assumed in the accident analysis. The primary and secondary containment isolation valves will continue to be operable or will be isolated as required by the existing specifications. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.7 TSTF-273-A, Revision 2, "Safety Function Determination Program Clarifications"

Description of Proposed Change
The proposed Technical Specification (TS) changes add explanatory text to the Bases for limiting condition for operation (LCO) 3.0.6 clarifying the "appropriate LCO for loss of function," and that consideration does not have to be made for a loss of power in determining loss of function. Explanatory text is also added to the programmatic description of the Safety Function Determination Program (SFDP) in Specification 5.5.12 to provide clarification of these same issues.

Differences Between the Proposed Change and the Approved Traveler
The TS numbering in Section 5.5 of the Hatch Technical Specifications is different from the ISTS Section 5.5 TS numbering. Hatch program 5.5.10, "Safety Function Determination Program," is equivalent to TS 5.5.12 in the ISTS. This has no effect on the requested change.

Summary of the Approved Traveler Justification
TS 5.5.12, "Safety Function Determination Program," implements the requirements of LCO 3.0.6. The SFDP program description in TS 5.5.12 is revised to clarify in the requirements that consideration does not have to be made for a loss of power in determining loss of function. TS 5.5.12 is also revised to incorporate an editorial change for consistency in meaning. The Bases for LCO 3.0.6 is revised to provide clarification of the "appropriate LCO for loss of function," and that consideration does not have to be made for a loss of power in determining loss of function.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
TSTF-273-A, Revision 2, was approved by the NRC as documented in a letter from William Beckner (NRC) to James Davis (NEI), dated August 16, 1999. TSTF-273-A, Revision 2 has been adopted by many plants as part of complete conversion to the ISTS, such as North Anna Power Station (ACN ML021200265). An example of a plant-specific NRC approval of the changes in TSTF-273-A, Revision 2 is Susquehanna Steam Electric Station, Units 1 and 2, Amendment Numbers 209/183 dated February 25, 2003 (ACN ML060860258).

List of Affected Pages
Unit 1
5.0-14
B3.0-9

Unit 2
5.0-14
B3.0-9

Applicable Regulatory Requirements/Criteria

Title 10 of the Code of Federal Regulations (10 CFR), 10 CFR 50.36(c)(2), states:

> Limiting conditions for operation. (i) Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.

The SFDP, as described in TS 5.5.10, implements the requirements of LCO 3.0.6, and ensures that loss of safety function is detected and appropriate actions are taken. There will be no changes to the plant design or operation such that compliance with the regulatory requirements and guidance document above would come into question. The plant and its systems will continue to comply with all applicable regulatory requirements. The proposed changes are consistent with NUREG-1433.

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

Signification Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed Technical Specification (TS) changes add explanatory text to the programmatic description of the Safety Function Determination Program (SFDP) in Specification 5.5.10 to clarify in the requirements that consideration does not have to be made for a loss of power in determining loss of function. The Bases for limiting condition for operations (LCO) 3.0.6 are revised to provide clarification of the "appropriate LCO for loss of function," and that consideration does not have to be made for a loss of power in determining loss of function. The changes are editorial and administrative in nature, and therefore do not increase the probability of any accident previously evaluated. No physical or operational changes are made to the plant. The proposed change does not change how the plant would mitigate an accident previously evaluated. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

   Response: No.

   The proposed changes are editorial and administrative in nature and do not result in a change in the manner in which the plant operates. The loss of function of any specific component will continue to be addressed in its specific TS LCO and plant configuration will be governed by the required actions of those LCOs. The proposed changes are clarifications that do not degrade the availability or capability of safety related equipment, and therefore do not create the possibility of a new or different kind of accident from any accident previously evaluated. There are no design changes associated with the proposed changes, and the changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed). The changes do not alter assumptions made in the safety analysis, and are consistent with the safety analysis assumptions and current plant operating practice. Due to the administrative nature of the changes, they cannot be an accident initiator. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed changes to TS 5.5.10 are clarifications and are editorial and administrative in nature. No changes are made the LCOs for plant equipment, the time required for the TS Required Actions to be completed, or the out of service time for the components involved. The proposed changes do not affect the safety analysis acceptance criteria for any analyzed event, nor is there a change to any safety analysis limit. The proposed changes do not alter the manner in which safety limits, limiting safety system settings or limiting conditions for operation are determined, nor is there any adverse effect on those plant systems necessary to assure the accomplishment of protection functions. The proposed changes will not result in plant operation in a configuration outside the design basis. Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.8 TSTF-283-A, Revision 3, "Modify Section 3.8 Mode Restriction Notes"

Description of Proposed Change
The proposed change revises several Specification 3.8.1, "AC Sources - Operating," Surveillance Notes to allow full or partial performance of the SRs to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced. These Surveillances currently have Notes prohibiting their performance in Modes 1 or 2, or in Modes 1, 2, or 3.

SR 3.8.1.6 (ISTS SR 3.8.1.8), which tests the transfer of Alternating (AC) sources from normal to alternate offsite circuits, contains a Note prohibiting performance in Mode 1 or 2. The Note is modified to state that performance is normally prohibited in Mode 1 or 2 but may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

SR 3.8.1.7 (ISTS SR 3.8.1.9), which tests the ability of the emergency diesel generator (DG) to reject a load greater than or equal to its associated single largest post-accident load, contains a Note prohibiting performance in Mode 1 or 2. An exception is provided for the swing DG. The Note is modified to state that performance is normally prohibited in Mode 1 or 2 but may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

SR 3.8.1.8 (ISTS SR 3.8.1.10), which tests emergency DG operation following a load rejection of greater than or equal to 2775 kW, contains a Note prohibiting performance in Mode 1 or 2. The Note is modified to state that performance is normally prohibited in Mode 1 or 2 but portions of the SR may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

SR 3.8.1.9 (ISTS SR 3.8.1.11), which tests the response to a loss of offsite power signal, contains a Note prohibiting performance in Mode 1, 2, or 3. The Note is modified to state that performance is normally prohibited in Mode 1, 2, or 3, but portions of the SR may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

SR 3.8.1.10 (ISTS SR 3.8.1.12), which tests response to an Emergency Core Cooling System (ECCS) initiation signal, contains a Note prohibiting performance in Mode 1 or 2. The Note is modified to state that performance is normally prohibited in Mode 1 or 2, but the SR may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

SR 3.8.1.11 (ISTS SR 3.8.1.13), which tests that each DGs automatic trips are bypassed on a loss of voltage signal concurrent with an ECCS initiation signal, contains a Note prohibiting performance in Mode 1, 2, or 3. The Note is modified to state that performance is normally prohibited in Mode 1, 2, or 3, but the SR may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

SR 3.8.1.12 (ISTS SR 3.8.1.14), which performs a 24 hour loaded test run of the DG, contains a Note prohibiting performance in Mode 1 or 2. The Note is modified to state that performance is normally prohibited in Mode 1 or 2, but the SR may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

SR 3.8.1.14 (ISTS SR 3.8.1.16), which verifies transfer from DG to offsite power, contains a Note prohibiting performance in Mode 1, 2, or 3. The Note is modified to state that performance is normally prohibited in Mode 1, 2, or 3, but portions of the SR may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

SR 3.8.1.15 (ISTS SR 3.8.1.17), which verifies than a DG operating in test mode will return to ready-to-load condition and energize the emergency load from offsite power on receipt of an ECCS initiation signal, contains a Note prohibiting performance in Mode 1, 2, or 3. The Note is modified to state that performance is normally prohibited in Mode 1, 2, or 3, but portions of the SR may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

SR 3.8.1.16 (ISTS SR 3.8.1.18), which verifies the interval between each sequenced load, contains a Note prohibiting performance in Mode 1, 2, or 3. The Note is modified to state that performance is normally prohibited in Mode 1, 2, or 3, but the SR may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

SR 3.8.1.17 (ISTS SR 3.8.1.19), which verifies the response to a loss of offsite power signal and Engineered Safety Features (ESF) actuation signal, contains a Note prohibiting performance in Mode 1, 2, or 3. The Note is modified to state that performance is normally prohibited in Mode 1, 2, or 3, but portions of the SR may be performed to re-establish Operability provided an assessment determines the safety of the plant is maintained or enhanced.

<u>Differences Between the Proposed Change and the Approved Traveler</u>
Previous amendment requests submitted by plants other than Hatch to adopt TSTF-283-A withdrew the proposed changes to the Specification 3.8.4 Surveillances following NRC questions. The following table summarizes the differences between the TSTF-283-A proposed Surveillance Note changes to the ISTS markups and the proposed Surveillance Note changes to the Hatch Technical Specifications:

TSTF-283-A Affected Surveillance and Description	Equivalent Hatch Surveillance and Proposed Change
SR 3.8.1.8 (transfer of AC sources from normal to alternate offsite circuit)	SR 3.8.1.6 - Adopt as proposed in TSTF-283-A.
SR 3.8.1.9 (largest post-accident load reject)	SR 3.8.1.7 - Adopt as proposed in TSTF-283-A.
SR 3.8.1.10 (load reject)	SR 3.8.1.8 - Adopt as proposed in TSTF-283-A.
SR 3.8.1.11 (response to loss of offsite power signal)	SR 3.8.1.9 - Adopt as proposed in TSTF-283-A.
SR 3.8.1.12 (response to an ECCS actuation signal)	SR 3.8.1.10 - Adopt as proposed in TSTF-283-A.
SR 3.8.1.13 (verify DG automatic trips are bypassed)	SR 3.8.1.11 - Adopt as proposed in TSTF-283-A.
SR 3.8.1.14 (DG 24 hour run)	SR 3.8.1.12 - Adopt as proposed in TSTF-283-A.
SR 3.8.1.16 (verify transfer from DG to offsite power)	SR 3.8.1.14 - Adopt as proposed in TSTF-283-A.
SR 3.8.1.17 (verify DG transfer from test mode)	SR 3.8.1.15 - Adopt as proposed in TSTF-283-A.
SR 3.8.1.18 (verify interval between sequencer load blocks)	SR 3.8.1.16 - Adopt as proposed in TSTF-283-A.
SR 3.8.1.19 (response to loss of offsite power signal and ESF actuation signal)	SR 3.8.1.17 - Adopt as proposed in TSTF-283-A.
SR 3.8.4.6 (battery charger capacity)	SR 3.8.4.6 - Not requested. Current SR has no Mode restriction.
SR 3.8.4.7 (battery capacity)	SR 3.8.4.7 - Not requested.
SR 3.8.4.8 (battery discharge test)	SR 3.8.4.8 - Not requested.

The TSTF-283-A Bases changes incorrectly state that the associated Notes restrict performance of the Surveillances in Mode 1 and 2. Several of the Surveillances restrict performance of the Surveillances in Mode 1, 2, or 3. This error is corrected in the Hatch Bases. Additionally, clarifying notations are added to the plant specific Bases text that describes how mode restrictions in the SR Notes are to be applied for the opposite unit.

Summary of the Approved Traveler Justification

The proposed changes to Specification 3.8.1 will potentially avoid a plant shutdown if corrective maintenance (planned or unplanned) performed during power operation results in the need to perform any of the revised Surveillances to demonstrate Operability. The proposed changes do not affect either the frequency of conducting the SRs, the surveillance to be performed, or the performance criteria specified in the SRs. The only change is to the reactor modes during which the surveillance may be performed.

The allowance to perform the Surveillances in currently prohibited Modes is restricted to only allow the Surveillances to be performed for the purpose of re-establishing Operability (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other

unanticipated operability concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed.

Note that the Maintenance Rule provision contained in 10 CFR 50.65(a)(4) states that before performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. This includes the performance of Surveillances to re-establish Operability. Therefore, in addition to the assessment required by the Surveillance Notes, an assessment of plant risk will also be performed.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
The NRC did not document their approval of TSTF-283-A, Revision 3 in a letter but it was incorporated into Revision 2 of the ISTS NUREGs. An example of a plant-specific NRC approval of the changes in TSTF-283-A, Revision 3 is Columbia Generating Station, Amendment Number 204, dated May 1, 2007 (ACN ML070920469).

List of Affected Pages
Unit 1
3.8-10
3.8-11
3.8-12
3.8-13
3.8-14
3.8-15
3.8-16
3.8-17
3.8-18
B3.8-24
B3.8-25
B3.8-26
B3.8-28
B3.8-29
B3.8-30
B3.8-31
B3.8-32
B3.8-33

B3.8-34
B3.8-35

Unit 2
3.8-10
3.8-11
3.8-12
3.8-13
3.8-14
3.8-15
3.8-16
3.8-17
3.8-18
B3.8-24
B3.8-25
B3.8-26
B3.8-28
B3.8-29
B3.8-30
B3.8-31
B3.8-32
B3.8-33
B3.8-34
B3.8-35

Applicable Regulatory Requirements/Criteria
Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criteria:

Criterion 18, Inspection and Testing of Electric Power Systems, states:
Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operation sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 24, Emergency Power for Protection Systems, states:
In the event of loss of offsite power, sufficient alternate sources of power shall be provided to permit the required functioning of the protection systems.

1967 GDC Criterion 25, Demonstration of Functional Operability of Protection Systems, states:

> Means shall be included for testing protection systems white the reactor is in operation to demonstrate that no failure or loss of redundancy has occurred.

The proposed change allows the performance of the Surveillances to re-establish Operability, and does not affect the design of the plant or its operations.

10 CFR 50.36(c)(3), "Technical Specifications," requires a licensee's Technical Specifications to have Surveillance Requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operations are within safety limits, and that the limiting conditions for operation will be met. The Surveillance Requirements may include mode restrictions based on the safety aspects of conducting the surveillances in excluded modes. The changes are consistent with NUREG-1433.

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

Significant Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change modifies Mode restriction Notes on eleven emergency diesel generator (DG) Surveillances to allow performance of the Surveillance in whole or in part to re-establish emergency DG Operability. The emergency DGs and their associated emergency loads are accident mitigating features, and are not an initiator of any accident previously evaluated. As a result the probability of any accident previously evaluated is not increased. The proposed change allows Surveillance testing to be performed in whole or in part to re-establish Operability of an emergency DG. The consequences of an accident previously evaluated during the period that the emergency DG is being tested to re-establish Operability are no different from the consequences of an accident previously evaluated while the emergency DG is inoperable. As a result, the consequences of any accident previously evaluated are not increased. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The purpose of Surveillances is to verify that equipment is capable of performing its assumed safety function. The proposed change will only allow the performance of the Surveillances to re-establish Operability and the proposed changes may not be used to remove an emergency DG from service. The proposed changes also require an assessment to verify that plant safety will be maintained or enhanced by performance of the Surveillance in the normally prohibited Modes. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.9 TSTF-284-A, Revision 3, "Add 'Met vs. Perform' to Technical Specification 1.4, Frequency"

Description of Proposed Change
The change inserts a discussion paragraph into Specification 1.4, and two new examples are added to facilitate the use and application of SR Notes that utilize the terms "met" and "perform."

Differences Between the Proposed Change and the Approved Traveler
None

Summary of the Approved Traveler Justification
The change inserts a discussion paragraph into Specification 1.4, and two new examples are added to facilitate the use and application of SR Notes that utilize the terms "met" and "perform." The added examples parallel existing examples 1.4-3 and 1.4-4 of Notes that allow for the SR to be "Not required to be performed . . .". The examples will alleviate misunderstanding and provide explicit direction for these types of SR Notes. Inserting this material will provide for better use, application, and understanding of these Notes.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
TSTF-284-A, Revision 3, was approved by the NRC as documented in a letter from William Beckner (NRC) to James Davis (NEI), dated February 16, 2000 (ACN ML003684596). TSTF-284-A, Revision 3 has been adopted by many plants as part of complete conversion to the ISTS, such as Beaver Valley Power Station (ACN ML070160593). An example of a plant-specific NRC approval of the changes in TSTF-284-A, Revision 3 is Columbia Generating Station, Amendment Number 205, dated December 13, 2007 (ACN ML073120270).

List of Affected Pages
Unit 1
1.4-1
1.4-2
1.4-5

Unit 2
1.4-1
1.4-2
1.4-5

Applicable Regulatory Requirements/Criteria
Title 10 of the Code of Federal Regulations (10 CFR), 10 CFR 50.36(c)(2), states:

> Limiting conditions for operation. (i) Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for

safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.

The changes insert a discussion paragraph into Specification 1.4, and two new examples are added to facilitate the use and application of SR Notes that utilize "met" and "perform." There will be no changes to the plant design or operations such that compliance with any of the regulatory requirements and guidance documents above would come into question. The plant and its systems will continue to comply with all applicable regulatory requirements. The changes are consistent with NUREG-1433.

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

Signification Hazards Consideration
SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed changes insert a discussion paragraph into Specification 1.4, and several new examples are added to facilitate the use and application of Surveillance Requirement (SR) Notes that utilize the terms "met" and "perform". The changes also modify SRs in multiple Specifications to appropriately use "met" and "perform" exceptions. The changes are administrative in nature because they provide clarification and correction of existing expectations, and therefore the proposed change does not increase the probability of any accident previously evaluated. No physical or operational changes are made to the plant. The proposed change does not significantly change how the plant would mitigate an accident previously evaluated. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

   Response: No.

   The proposed changes are administrative in nature and do not result in a change in the manner in which the plant operates. The proposed

changes provide clarification and correction of existing expectations that do not degrade the availability or capability of safety related equipment, and therefore do not create the possibility of a new or different kind of accident from any accident previously evaluated. There are no design changes associated with the proposed changes, and the changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed). The changes do not alter assumptions made in the safety analysis, and are consistent with the safety analysis assumptions and current plant operating practice. Due to the administrative nature of the changes, they cannot be an accident initiator. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed changes are administrative in nature and do not result in a change in the manner in which the plant operates. The proposed changes provide clarification and correction of existing expectations that do not degrade the availability or capability of safety related equipment, or alter their operation. The proposed changes do not affect the safety analysis acceptance criteria for any analyzed event, nor is there a change to any safety analysis limit. The proposed changes do not alter the manner in which safety limits, limiting safety system settings or limiting conditions for operation are determined, nor is there any adverse effect on those plant systems necessary to assure the accomplishment of protection functions. The proposed changes will not result in plant operation in a configuration outside the design basis. Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.10 TSTF-295-A, Revision 0, "Modify Note 2 to Actions of PAM Table to Allow Separate Condition Entry for Each Penetration"

Description of Proposed Change
Specification 3.3.3.1, "Post Accident Monitoring (PAM) Instrumentation," Function 6, is renamed from "Primary Containment Isolation Valve Position" to "Penetration Flow Path Primary Containment Isolation Valve Position."

Differences Between the Proposed Change and the Approved Traveler
The numbering of PAM functions in Table 3.3.3.1-1 of the Hatch Technical Specifications is different from the numbering in TSTF-295-A. Functions 8 and 13 in TSTF-295-A correspond to functions 6 and 9 in Table 3.3.3.1-1 of the Hatch Technical Specifications, respectively. This has no effect on the requested change.

Adoption of the changes identified in TSTF-295-A for Specification 3.3.3.1, Function 13, "Suppression Pool Water Temperature," have been modified to reflect the Hatch suppression pool water temperature monitoring and indication instrumentation configuration. TSTF-295-A is based on a configuration that has temperature monitoring instrumentation located in the suppression pool at the relief valve discharge locations. The Hatch suppression pool water temperature monitoring and indication configuration and strategy is based on monitoring of water temperature in quadrants of the suppression pool. The proposed changes preserve the intent of the Hatch Technical Specifications, which is that Operability of the suppression pool water temperature functions is determined by quadrant, and of TSTF-295-A, which is to clarify that separate Condition entry is allowed for each function.

Summary of the Approved Traveler Justification
The proposed change is a clarification which identifies that separate condition entry is allowed for each penetration flow path for the PAM primary containment isolation valve (PCIV) position indication function and for each quadrant of suppression pool temperature indication.

The proposed change is made to clarify how to apply the Actions Note to these two functions. The Actions Note states "Separate Condition entry is allowed for each Function." The changes clarify that separate condition entry is allowed for each penetration flow path for the PAM PCIV position indication function and for each relief valve discharge location suppression pool temperature indication. This change will provide consistency between the PCIV position indication function of the PAM Specification and the allowance in the primary containment penetration Specification for PCIVs (Specification 3.6.1.3). Similar to the specification for PCIVs, each penetration flow path should be evaluated separately for Operability of the PAM function. The PAM specification requires a minimum of one channel of PCIV position indication in the control room to be Operable for each active PCIV in a containment penetration flow path. Current Actions provide appropriate compensatory actions for each inoperable indication channel. The change reduces the potential for a shutdown of the unit due to misinterpretation of the requirements.

These changes are acceptable because they clarify the intended application of action requirements for inoperable channels of these PAM functions and are consistent with the action requirements for PCIVs. They do not reduce any existing action requirements for these PAM functions.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
The NRC documented their approval of TSTF-295-A, Revision 0, in a letter from William Beckner (NRC) to James Davis (NEI) dated December 21, 1999 (ACN ML993630256). An example of a plant-specific NRC approval of the changes in TSTF-295-A, Revision 0, is Columbia Generating Station, Amendment Number 208, dated September 15, 2008 (ACN ML081900507).

Unit 1
3.3-25
B3.3-63
B3.3-64

Unit 2
3.3-25
B3.3-63
B3.3-64

Applicable Regulatory Requirements/Criteria
Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criteria:

Criterion 13, Instrumentation and Controls, states:

> Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Criterion 64, Monitoring Radioactivity Releases, states:

> Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss-of-coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 12, Instrumentation and Control, states:
Instrumentation and controls shall be provided as required to monitor and maintain variables within prescribed operating ranges.

1967 GDC Criterion 17, Monitoring Radioactivity Releases, states:
Means shall be provided for monitoring the containment atmosphere, the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

The proposed changes are clarifications of the existing requirements and do not affect the design of the PAM instrumentation. The changes are consistent with NUREG-1433.

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

Significant Hazards Consideration
SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change clarifies the separate condition entry Note in Specification 3.3.3.1, "Post Accident Monitoring (PAM) Instrumentation," for Function 6, "Primary Containment Isolation Valve Position," and Function 9, "Suppression Pool Water Temperature." The proposed change does not affect any plant equipment, test methods, or plant operation, and are not initiators of any analyzed accident sequence. The actions taken for inoperable PAM channels are not changed. Operation in accordance with the proposed Technical Specifications will ensure that all analyzed accidents will continue to be mitigated as previously analyzed. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

Response: No.

The proposed change will not affect the operation of plant equipment or the function of any equipment assumed in the accident analysis. The PAM channels will continue to be operable or the existing, appropriate actions will be followed. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.11 TSTF-306-A, Revision 2, "Add Action to LCO 3.3.6.1 to Give Option to Isolate the Penetration"

Description of Proposed Change
The proposed change revises Specification 3.3.6.1, "Primary Containment Isolation Instrumentation." An Actions Note is added allowing penetration flow paths to be unisolated intermittently under administrative controls. The traversing incore probe (TIP) isolation system is also segregated into a separate Function, allowing 12 hours to place the channel in trip and 24 hours to isolate the penetration. A new Condition G is added for the new TIP isolation system Function. Condition G is referenced from Required Action C.1 when Conditions A or B are not met. The subsequent Actions are renumbered.

Differences Between the Proposed Change and the Approved Traveler
The HNP Technical Specifications do not contain an Action that is equivalent to the ISTS Condition G referenced by the new TIP isolation system Function. This action was added and the subsequent Actions renumbered, consistent with the ISTS. Additionally, Condition G is added to the scope of (renumbered) Condition H. Condition H provides end state requirements when the requirements of Condition G are not met. This change is not indicated in the TSTF, but is consistent with Revision 2 of the ISTS.

Supplemental text is also added to the Bases for TS 3.3.6.1, Condition A. The added text provides information about the Completion Times for Functions 7.a and 7.b that was not included in the markups for TSTF-306-A or the ISTS.

Summary of the Approved Traveler Justification
Specification 3.6.1.3, "Primary Containment Isolation Valves," contains an allowance to open primary containment isolation valves (PCIVs) intermittently under administrative controls. The isolation instrumentation described in Specification 3.3.6.1 serves as a support system for the PCIVs. The Actions for inoperability of the instrumentation should not be more restrictive than the Actions for inoperability of the PCIVs. Therefore, the allowance to intermittently open penetrations (under administrative control) that are isolated to comply with Actions is added to the Specification 3.3.6.1 Actions as Note 1.

The TIP System isolation is segregated as a separate isolation Function with the associated Action that is referenced from Required Action C.1 allowing penetration isolation rather than a unit shutdown. The Actions for inoperable primary containment isolation instrumentation require a unit shutdown. This action is overly restrictive for inoperable TIP system isolation instrumentation. The TIP system uses a small bore penetration (approximately 1/2 inch), and its isolation in a design basis event is via the manually operated shear valves. The ability to manually isolate the TIP system by either the normal isolation valve or the shear valve would be unaffected by inoperable instrumentation. Therefore, the option to isolate the penetration and to continue plant operation is provided. In order to implement this allowance, a separate isolation instrumentation Function is being provided for the TIP system. The Completion Time provided to isolate the penetration is 24 hours, which is the Completion Time provided in the ISTS for penetration isolation when the manual isolation function is inoperable.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification

The Hatch Technical Specifications do not contain an Action equivalent to ISTS 3.3.6.1, Action G. The ISTS references Action G for manual isolation functions, which do not appear in the Hatch Specification 3.3.6.1. Therefore, ISTS Action G is added to the Hatch Technical Specifications. The 24 hour Completion Time is acceptable due to the fact that the TIP System penetration is a small bore (approximately ½ inch), its isolation in a design basis event (with loss of offsite power) would be via the manually operated shear valves, and the ability to manually isolate by either the normal isolation valve or the shear valve is unaffected by the inoperable instrumentation.

Licensee Commitments Required to Adopt this Change

None

NRC Approval

The NRC did not document their approval of TSTF-306-A, Revision 2. However, TSTF-306-A, Revision 2 was incorporated in Revision 2 of the ISTS NUREGs. An example of a plant-specific NRC approval of the changes in TSTF-306-A, Revision 1 is River Bend Station, Unit 1, Amendment Number 165, dated August 11, 2009 (ACN ML092010370).

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Applicable Regulatory Requirements/Criteria

Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criteria:

Criterion 54, Piping Systems Penetrating Containment, states:

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to periodically test the operability of isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Criterion 55, Reactor Coolant Pressure Boundary Penetrating Containment, states:

Each line that is part of the RCPB and penetrates the primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, e.g., instrument lines, are acceptable on some other defined basis:

(1) One locked-closed isolation valve inside and one locked-closed isolation valve outside containment.

(2) One automatic valve inside and one locked-closed isolation valve outside containment.

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

(4) One automatic isolation valve in inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Criterion 56, Primary Containment Isolation, states:

Each line connecting directly to the containment atmosphere and penetrating the primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated

that the containment isolation provisions for a specific class of lines, e.g., instrument lines, are acceptable on some other defined basis:

(1) One locked-closed isolation valve inside and one locked-closed isolation valve outside containment.

(2) One automatic valve inside and one locked-closed isolation valve outside containment.

(3) One locked closed isolation valve inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

(4) One automatic isolation valve in inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Criterion 57, Closed System Isolation Valves, states:
Each line penetrating the primary reactor containment that is neither part of the RCPB nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, locked-closed, or capable of remote-manual operation. This valve shall be located outside and as close to the containment as practical.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 51, Reactor Coolant Pressure Boundary Outside Containment, states:
If part of the reactor coolant pressure boundary is outside the containment, appropriate features an necessary shall be provided to protect the health and safety of the public in case of an accidental rupture in that part. Determination of the appropriateness of features such as isolation valves and additional containment shall include consideration of the environmental and population conditions surrounding the site.

1967 GDC Criterion 53, Containment Isolation Valves, states:
Penetrations that require closure for the containment function shall be protected by redundant valving and associated apparatus.

1967 GDC Criterion 56, Provisions for Testing of Penetrations, states:
Penetrations shall be made for testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at design pressure at any time.

1967 GDC Criterion 57, Provisions for Testing of Isolation Valves, states:

> Capability shall be provided for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits.

These criteria specify the number, type, and positions of CIVs required for containment piping penetrations. However, these criteria do not contain provisions describing actions to take if containment isolation valves become inoperable during plant operation.

The regulations in 10 CFR 50.36, "Technical Specifications," provide general requirements for the establishment of Technical Specifications, including limiting conditions for operation, action requirements, and Surveillance Requirements, but do not give specific guidance on Actions and Completion Times when a limiting condition for operation is not met.

The best guidance is that contained in the STS, NUREG-1433. The proposed Actions and Completion Times are consistent with those given in NUREG-1433.

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

Significant Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change revises Specification 3.3.6.1, "Primary Containment Isolation Instrumentation." An Actions Note is added allowing penetration flow paths to be unisolated intermittently under administrative controls. The traversing incore probe (TIP) isolation system is segregated into a separate Function, allowing 12 hours to place the channel in trip and 24 hours to isolate the penetration. A new Action G is added which is referenced by the new TIP isolation system Function. The subsequent Actions are renumbered. The proposed change does not affect any plant equipment, test methods, or plant operation, and are not initiators of any analyzed accident sequence. The allowance to unisolate a penetration flow path will not have a significant effect on mitigation of any accident previously evaluated because the penetration flow path can be isolated, if needed, by a dedicated operator. The option to isolate a TIP System penetration will ensure the penetration will perform as assumed in the accident analysis. Operation in accordance with the proposed Technical

Specifications will ensure that all analyzed accidents will continue to be mitigated as previously analyzed. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change will not affect the operation of plant equipment or the function of any equipment assumed in the accident analysis. The allowance to unisolate a penetration flow path will not have a significant effect on a margin of safety because the penetration flow path can be isolated manually, if needed. The option to isolate a TIP System penetration will ensure the penetration will perform as assumed in the accident analysis. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.12 TSTF-308-A, Revision 1, "Determination of Cumulative and Projected Dose Contributions in RECP"

Description of Proposed Change
The proposed change revises Specification 5.5.4, "Radioactive Effluent Controls Program," paragraph e, to describe the original intent of the dose projections.

Differences Between the Proposed Change and the Approved Traveler
None

Summary of the Approved Traveler Justification
The proposed change revises Specification 5.5.4, "Radioactive Effluent Controls Program," paragraph e, to describe the original intent of the required dose projections.

The NRC's draft Standard Technical Specifications for four-loop Westinghouse plants (8/14/87 letter to Texas Utilities) included Radioactive Effluent Technical Specifications. The two Surveillances in those draft Standard Technical Specifications reflect the intent of Hatch Specification 5.5.4, paragraph e. SR 4.11.1.2 for Dose stated, "Cumulative dose contributions from liquid effluents for the current calendar quarter and the current calendar year shall be determined in accordance with the methodology and parameters in the ODCM at least once per 31 days." SR 4.11.1.3.1 for Liquid Radwaste Treatment System stated, "Doses due to liquid releases from each unit to UNRESTRICTED AREAS shall be projected at least once per 31 days in accordance with the methodology and parameters in the ODCM when Liquid Radwaste Treatment Systems are not being fully utilized." Generic Letter 89-01 inappropriately combined these two Surveillance Requirements for cumulative and projected doses such that they can be interpreted to require determining projected dose contribution for the current calendar quarter and current calendar year every 31 days. Therefore, the proposed change clarifies the wording in 5.5.4.e to not require dose projections for a calendar quarter and a calendar year every 31 days.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
The NRC did not document their approval of TSTF-308-A, Revision 1. However, TSTF-308-A, Revision 1 was incorporated in Revision 2 of the ISTS NUREGs. An example of a plant-specific NRC approval of the changes in TSTF-308-A, Revision 1 is LaSalle County Station, Units 1 and 2, Amendment Numbers 190/177, dated February 23, 2009 (ACN ML083190337).

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5.0-9

Applicable Regulatory Requirements/Criteria
Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criterion:

Criterion 64, Monitoring Radioactivity Releases, states:
Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss-of-coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 17, Monitoring Radioactivity Releases, states:
Means shall be provided for monitoring the containment atmosphere, the facility effluent discharge paths, and the facility environs for radioactivity that could be released from normal operations, from anticipated transients, and from accident conditions.

The proposed change is an administrative requirement related to monitoring effluent discharge. It clarifies the intent of the NRC's guidance published in Generic Letter 89-01. The change is consistent with NUREG-1433.

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

Significant Hazards Consideration
SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change revises Specification 5.5.4, "Radioactive Effluent Controls Program," paragraph e, to describe the original intent of the dose projections. The cumulative and projection of doses due to liquid releases are not an assumption in any accident previously evaluated and have no effect on the mitigation of any accident previously evaluated. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change revises Specification 5.5.4, "Radioactive Effluent Controls Program," paragraph e, to describe the original intent of the dose projections. The cumulative and projection of doses due to liquid releases are administrative tools to assure compliance with regulatory limits. The proposed change revises the requirement to clarify the intent, thereby improving the administrative control over this process. As a result, any effect on the margin of safety should be minimal. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.13 TSTF-318-A, Revision 0, "Revise 3.5.1 for One LPCI Pump Inoperable in Each of Two ECCS Divisions"

Description of Proposed Change
The proposed change adds a provision to Condition A of Specification 3.5.1, "ECCS – Operating," to allow one Low Pressure Coolant Injection (LPCI) pump to be inoperable in each subsystem for a period of seven days.

Differences Between the Proposed Change and the Approved Traveler
TSTF-318-A includes modifications to ISTS Specification 3.5.1, Condition F. This Condition does not appear in the Hatch Technical Specifications. Additionally, an editorial change to the Bases for HNP TS 3.5.1, Condition F is provided. Condition F of HNP TS 3.5.1 is equivalent to Condition H in NUREG-1433.

Summary of the Approved Traveler Justification
The standard BWR/4 configuration consists of two Low Pressure Coolant Injection (LPCI) (ECCS injection) pumps in each of two subsystems, for a total of four LPCI pumps. ISTS 3.5.1 Condition A allows one low pressure ECCS injection/spray subsystem (e.g., one or both LPCI pumps in one subsystem; total of two LPCI pumps) to be inoperable for 7 days. The proposed change to add a new entry into Condition A would also allow two inoperable LPCI pumps (one in each of the subsystems) for 7 days.

When compared to plant operation in Condition A (one LPCI subsystem inoperable), the proposed addition to Condition A with one LPCI pump inoperable in both subsystems, provides enhanced reliability that at least one LPCI pump will be available for post-LOCA injection. With one subsystem inoperable a LOCA can eliminate the availability of the remaining subsystem for injection; while a LOCA during operation with only one LPCI pump in each ECCS division could only remove the availability of one of the two remaining LPCI pumps. Additionally, during an event that does not impact LPCI availability, and that requires LPCI injection, one pump in each LPCI subsystem has the ability to provide more injection flow than two pumps in a single subsystem.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
The NRC documented their approval of TSTF-318-A, Revision 0, in a letter from William D. Beckner (NRC) to James Davis (NEI) dated June 20, 1999. This document is not publically available in NRC ADAMS, but a copy can be provided on request. An example of a plant-specific NRC approval of the changes in TSTF-318-A is Cooper Nuclear Station, Amendment Number 203, dated March 31, 2004 (ACN ML040910467).

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Applicable Regulatory Requirements/Criteria
Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criterion:

Criterion 35, Emergency Core Cooling, states:
A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 44, Emergency Core Cooling Systems Capability, states:
At least two emergency core cooling systems, preferably of different design principles, each with a capability for accomplishing abundant emergency core cooling, shall be provided. Each emergency core cooling system and the core shall be designed to prevent fuel and clad damage that would interfere with the emergency core cooling function and to limit the clad metal-water reaction to negligible amounts for all sizes of breaks in the reactor coolant pressure boundary, including the double-ended rupture of the largest pipe. The performance of each emergency core cooling system shall be evaluated conservatively in each area of uncertainty. The systems shall not share active components and shall not share other features or components unless it can be demonstrated that (a) the capability of the shared feature or component to perform its required function can be readily ascertained during reactor operation, (b) failure of the shared feature or component does not initiate a loss-of-coolant accident, and (c) capability of the shared feature or component to

perform its required function is not impaired by the effects of a loss-of-coolant accident and is not lost during the entire period this function is required following an accident.

The proposed changes do not affect the design of the emergency core cooling system and enhances the reliability of the emergency core cooling function under certain conditions. The proposed changes are consistent with NUREG-1433.

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

Significant Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change adds a provision to Condition A of Technical Specification (TS) 3.5.1 to allow one Low Pressure Coolant Injection (LPCI) pump to be inoperable in each subsystem for a period of seven days. The change to allow one LPCI pump to be inoperable in both subsystems is more reliable than what is currently allowed by Condition A, which requires entry into shutdown limiting condition for operation (LCO) 3.0.3 under these conditions. The LPCI mode of the Residual Heat Removal system is not assumed to be initiator of any analyzed event sequence. The consequences of an accident previously evaluated under the proposed allowance are no different than the consequences under the existing requirements. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change adds a provision to Condition A of Technical Specification TS 3.5.1 to allow one LPCI pump to be inoperable in each subsystem for a period of seven days. The change to allow one LPCI pump to be inoperable in both subsystems is more reliable than what is currently allowed by Condition A, which requires entry into shutdown LCO 3.0.3 under these conditions. The proposed change does not affect any safety analysis assumptions. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.14 TSTF-322-A, Revision 2, "Secondary Containment and Shield Building Boundary Integrity SRs"

Description of Proposed Change
The proposed change revises Specification 3.6.4.1, "Secondary Containment," SRs 3.6.4.1.3 and 3.6.4.1.4 to clarify the intent of the Surveillances.

Differences Between the Proposed Change and the Approved Traveler
The equivalent Hatch Surveillances contain a Note which reflects the Standby Gas Treatment (SGT) system design. The secondary containment encompasses three separate zones: the Unit 1 reactor building, the Unit 2 reactor building, and the common refueling floor. The secondary containment can be modified to exclude the certain zones from the secondary containment Operability requirement during various plant operating conditions with the appropriate controls. In some cases, the design assumes that at least two SGT subsystems are in operation. As a result, the word "required" was added to the Surveillance and Frequency when referring to the SGT subsystems to reflect the fact that not all SGT subsystems are required and references to one subsystem was revised to reflect that more than one subsystem may be required.

Additionally, changes clarifying that the frequencies for SRs 3.6.4.1.3 and 3.6.4.1.4 are "for each subsystem" are not adopted. The frequencies for these SRs are controlled under a Surveillance Frequency Control Program (SFCP) and are no longer included in the Technical Specifications. NRC approval of the license change implementing the SFCP was provided in Amendment Numbers 266/210, dated January 3, 2012 (ACN ML11108A129).

Summary of the Approved Traveler Justification
The secondary containment boundary integrity surveillances ensure the secondary containment is Operable by verifying the leak tightness of the boundary is within the assumptions of the accident analyses. However, the surveillances are written in such a manner that they imply that if a SGT subsystem is inoperable, the secondary containment surveillances are failed (i.e., "Verify each standby gas treatment (SGT) subsystem will/can"). That is not the intent of these surveillances. To clarify the intent, the surveillances have been rephrased to more clearly convey the intent of the surveillances, which is to verify the secondary containment is operable. Under the proposed wording, the secondary containment surveillances can still be considered met if a SGT subsystem is inoperable.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
The NRC documented their approval of TSTF-322-A, Revision 2, in a letter from William D. Beckner (NRC) to James Davis (NEI) dated February 16, 2000 (ACN ML003684596). An example of a plant-specific NRC approval of the

changes in TSTF-322-A is Peach Bottom Units 2 and 3 Amendment Numbers 259/262 dated May 10, 2006 (ACN ML061070292).

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Applicable Regulatory Requirements/Criteria
Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criterion:

Criterion 57, Closed System Isolation Valves, states:
Each line penetrating the primary reactor containment that is neither part of the RCPB nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, locked-closed, or capable of remote-manual operation. This valve shall be located outside and as close to the containment as practical.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 53, Containment Isolation Valves, states:
Penetrations that require closure for the containment function shall be protected by redundant valving and associated apparatus.

These criteria specify the design requirements for the primary and secondary containment.

The regulations in 10 CFR 50.36, "Technical Specifications," provide general requirements for the establishment of Technical Specifications, including limiting conditions for operation, action requirements, and Surveillance Requirements, but do not give specific guidance on the content of Surveillance Requirements.

The best guidance is that contained in the STS, NUREG-1433. The proposed changes are clarifications to the existing requirements. The proposed Surveillance Requirements are consistent with NUREG-1433.

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

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

Significant Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change revises Specification 3.6.4.1, "Secondary Containment," Surveillance Requirements (SRs) 3.6.4.1.3 and 3.6.4.1.4 to clarify the intent of the Surveillances. The secondary containment and the standby gas treatment (SGT) system are not initiators of any accident previously evaluated. Operation in accordance with the proposed Technical Specifications will ensure that all analyzed accidents will continue to be mitigated as previously analyzed. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change is an clarification of the intent of the surveillances to ensure that the secondary containment is not inappropriately declared inoperable when a SGT subsystem is inoperable. The safety functions of the secondary containment and the SGT system are not affected. This change is a correction that ensures that the intent of the secondary containment surveillances is clear. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10

CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.15 TSTF-323-A, Revision 0, "EFCV Completion Time to 72 hours"

Description of Proposed Change
The proposed change revises Specification 3.6.1.3, "Primary Containment Isolation Valves," Action C, to provide a 72 hour Completion Time instead of a 12 hour Completion Time to isolate an inoperable excess flow check valve (EFCV).

Differences Between the Proposed Change and the Approved Traveler
None

Summary of the Approved Traveler Justification
The BWR/4 design includes a class of single-isolation valve penetrations (i.e., instrumentation lines with an EFCV) that were inadvertently not included in the markup for TSTF-30-A. TSTF-30-A, Revision 2, extended the Completion time to 72 hours for inoperable containment isolation valves where there was only a single valve on the containment penetration. (See Section 2.1) This was in recognition of the fact that these penetrations were designed with some other acceptable barrier (e.g., closed system) in addition to the isolation valve. EFCVs similarly are on penetrations that have been found to have an acceptable barrier(s) in the event that the single isolation valve failed. TSTF-323-A, Revision 0 was provided subsequent to approval of TSTF-30-A, Revision 2 to add clarity and understanding to the format and presentation of changes that were approved in TSTF-30-A, Revision 2. TSTF-30-A, Revision 3, was later approved to extend the Completion time to 72 hours for inoperable EFCVs. Specification 3.6.1.3, Required Action C.1 is revised to eliminate the exception for EFCV Completion Times, which will provide the TSTF-30-A approved Completion Time of 72 hours for inoperable EFCVs

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
The NRC documented their approval of TSTF-323-A, Revision 0, in a letter from William D. Beckner (NRC) to James Davis (NEI) dated March 22, 1999 (ACN 9903250187). An example of a plant-specific NRC approval of the changes in TSTF-323-A, Revision 0 is Columbia Generating Station, Amendment Number 208, dated September 15, 2008 (ACN ML081900507).

List of Affected Pages
Unit 1
3.6-9
B3.6-20

Unit 2
3.6-9
B3.6-20

Applicable Regulatory Requirements/Criteria

Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criteria:

Criterion 54, Piping Systems Penetrating Containment, states:

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to periodically test the operability of isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Criterion 55, Reactor Coolant Pressure Boundary Penetrating Containment, states:

Each line that is part of the RCPB and penetrates the primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, e.g., instrument lines, are acceptable on some other defined basis:

(5) One locked-closed isolation valve inside and one locked-closed isolation valve outside containment.

(6) One automatic valve inside and one locked-closed isolation valve outside containment.

(7) One locked closed isolation valve inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

(8) One automatic isolation valve in inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Criterion 56, Primary Containment Isolation, states:

Each line connecting directly to the containment atmosphere and penetrating the primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, e.g., instrument lines, are acceptable on some other defined basis:

(5) One locked-closed isolation valve inside and one locked-closed isolation valve outside containment.

(6) One automatic valve inside and one locked-closed isolation valve outside containment.

(7) One locked closed isolation valve inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

(8) One automatic isolation valve in inside and one automatic isolation valve outside containment – A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Criterion 57, Closed System Isolation Valves, states:

Each line penetrating the primary reactor containment that is neither part of the RCPB nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, locked-closed, or capable of remote-manual operation. This valve shall be located outside and as close to the containment as practical.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 51, Reactor Coolant Pressure Boundary Outside Containment, states:

If part of the reactor coolant pressure boundary is outside the containment, appropriate features an necessary shall be provided to protect the health and safety of the public in case of an accidental rupture in that part. Determination of the appropriateness of features such as isolation valves and additional containment shall include consideration of the environmental and population conditions surrounding the site.

1967 GDC Criterion 53, Containment Isolation Valves, states:

Penetrations that require closure for the containment function shall be protected by redundant valving and associated apparatus.

1967 GDC Criterion 56, Provisions for Testing of Penetrations, states:

Penetrations shall be made for testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at design pressure at any time.

1967 GDC Criterion 57, Provisions for Testing of Isolation Valves, states: Capability shall be provided for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits.

These criteria specify the number, type, and positions of CIVs required for containment piping penetrations. However, these criteria do not contain provisions describing actions to take if containment isolation valves become inoperable during plant operation.

The regulations in 10 CFR 50.36, "Technical Specifications," provide general requirements for the establishment of Technical Specifications, including limiting conditions for operation, action requirements, and Surveillance Requirements, but do not give specific guidance on Actions and Completion Times when a limiting condition for operation is not met.

The best guidance is that contained in the STS, NUREG-1433. The proposed Actions and Completion Times are consistent with those given in NUREG-1433.

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

Significant Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change revises Specification 3.6.1.3, "Primary Containment Isolation Valves," Action C, to provide a 72 hour Completion Time instead of a 12 hour Completion Time to isolate an inoperable excess flow check valve (EFCV). The primary containment isolation valves (PCIVs) are not an initiator of any accident previously evaluated. The consequences of a previously evaluated accident during the extended Completion Time are the same as the consequences during the existing Completion Time. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change extends the Completion Time to isolate an inoperable primary containment penetration equipped with an excess flow check valve from 12 hours to 72 hours. The PCIVs serve to mitigate the potential for radioactive release from the primary containment following an accident. The design and response of the PCIVs to an accident are not affected by this change. The revised Completion Time is appropriate given the EFCVs are on penetrations that have been found to have acceptable barrier(s) in the event that the single isolation valve fails. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.16 TSTF-374-A, Revision 0, "Revision to TS 5.5.13 and Associated TS Bases for Diesel Fuel Oil"

Description of Proposed Change
The proposed change revises Specification 5.5.9, "Diesel Fuel Oil Testing Program," to remove references to the specific American Society for Testing and Materials (ASTM) Standard from the Administrative Controls Section of TS, and places them in a licensee-controlled document. Also, alternate criteria are added to establish the acceptability of new fuel oil for use prior to and following the addition to storage tanks.

Differences Between the Proposed Change and the Approved Traveler
The TS numbering in Section 5.5 of the Hatch Technical Specifications differs from the ISTS Section 5.5 TS numbering. TS 5.5.9, "Diesel Fuel Oil Testing Program," in the Hatch Technical Specifications is equivalent to TS 5.5.10 in the ISTS. This has no effect on the requested change.

TSTF-374-A, Revision 0, removes references to specific ASTM Standards from the description of the Diesel Fuel Oil Testing Program in Section 5.5 of the TS, and places the references in the Bases description for SR 3.8.3.3. The ISTS Bases for SR 3.8.3.3 provides a summary description of the tests, limits, and applicable ASTM standards used for testing the properties of new and stored diesel fuel oil in accordance with the Diesel Fuel Oil Program. Hatch SR 3.8.3.3, and its associated Bases, are very different from the ISTS SR 3.8.3.3 and Bases, and incorporation of the TSTF-374 Bases changes would require a significant revision that would include changes outside the scope of TSTF-374. However, the information that TSTF-374 places in the Technical Specification Bases is currently in the licensee-controlled documents for the Diesel Fuel Oil Program and its implementing test procedures.

References to specific ASTM standards and test methods that are removed from TS 5.5.9, and the references to supplemental ASTM standards and test methods for API gravity, water and sediment, sulfur content, and particulate concentration that TSTF-374 would add to the Bases for SR 3.8.3.3, are currently reflected in the licensee-controlled documents for the Diesel Fuel Oil Program, and its implementing test procedures, and no additional changes to these documents are needed to implement the revised requirements. Similar to the TS Bases, changes to these licensee-controlled documents are performed in accordance with the provisions of 10 CFR 50.59.

To achieve consistency between the Hatch Technical Specification Diesel Fuel Oil Testing Program and the ISTS Diesel Fuel Oil Testing Program, Hatch TS 5.5.9.a is revised to incorporate the ISTS specific requirements for acceptability of new fuel oil prior to and following the addition to storage tanks. The TSTF-374 proposed changes to allow the water and sediment content test are incorporated into the revised requirements for Hatch TS 5.5.9.a. Due to an existing commitment to perform water and sediment content test for new and stored fuel, Hatch is not incorporating the option to perform the "clear and bright" test in lieu of the water and sediment content test.

Summary of the Approved Traveler Justification

The requirements outlined in ISTS TS 5.5.10, "Diesel Fuel Oil Testing Program," ensure that diesel fuel oil sampling and testing requirements as well as acceptance criteria for new and stored fuel oil will be in accordance with applicable ASTM Standards. These tests are a means of determining whether fuel oil is of the appropriate grade (i.e., proper fuel oil quality) and has not been contaminated with substances that would have a detrimental impact on the ability of the diesel engines to perform their safety function.

Specifically, the Diesel Fuel Oil Testing Program establishes acceptability limits for new fuel oil prior to its addition to the storage tanks. Acceptability is based on the fuel oil meeting the requirements for API gravity or absolute specific gravity; flash point and kinematic viscosity; and a clear and bright appearance with proper color, or water and sediment content. With the exception of those properties mentioned above, other new fuel oil properties are verified to be within limits for ASTM 2D fuel oil within 31 days following addition of the new fuel oil to the storage tanks. Additionally, the program will continue to require that total particulate concentration of the stored fuel oil be < 10 mg/l when tested every 92 days.

By removing references to specific ASTM Standards from the TS Section 5.5 description of the Diesel Fuel Oil Testing Program, and placing them in licensee-controlled documents, the changes identified in TSTF-374-A, Revision 0 provide the flexibility to address future changes in Environmental Protection Agency (EPA) regulations for fuel oil or revisions to the ASTM standards. Additionally, the alternative to the "clear and bright" acceptance test for new fuel is added to address changes in EPA requirements. Requirements for testing of diesel fuel oil to ASTM Standards are maintained in the TS, but references to the specific ASTM Standards are placed in licensee controlled documents. Changes to this licensee controlled document are performed in accordance with the provisions of 10 CFR 50.59.

TSTF-374-A was reviewed and accepted by the NRC staff and has been incorporated into each of the STS NUREGs. The proposed TS changes will continue to ensure the quality of both new fuel oil and stored fuel oil designated for use in the emergency diesel generators.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification

None

Licensee Commitments Required to Adopt this Change

None

NRC Approval

The NRC documented their approval of TSTF-374-A, Revision 0, as a "Notice of Availability of Model Application" dated April 14, 2006 (ACN ML061040356). An example of a plant-specific NRC approval of the changes in TSTF 323 A, Revision 0 is Millstone Power Station, Unit 2, Amendment Number 313, dated March 5, 2013 (ACN ML13043A176).

List of Affected Pages
Unit 1
5.0-13

Unit 2
5.0-13

Applicable Regulatory Requirements/Criteria
Regulatory Guide 1.137, Revision 1, "Fuel Oil Systems for Standby Diesel Generators" describes a method acceptable to the NRC staff for complying with the Commission's regulations regarding diesel fuel oil systems for standby diesel generators and assurance of adequate diesel fuel oil quality.

The proposed change involves an administrative change in the licensee controlled document that lists the ASTM Standards used to test diesel fuel oil. The change does not involve a physical change to the diesel fuel oil, lube oil or air start systems, or a reduction in diesel fuel oil testing requirements. Therefore, conformance with Regulatory Guide 1.137, as it applies to the design and testing of the diesel engine fuel oil system, is not adversely affected.

The regulations in 10 CFR 50.36, "Technical Specifications," provide general requirements for the establishment of Technical Specifications, including limiting conditions for operation, action requirements, and Surveillance Requirements, but do not provide specific guidance on the MODEs in which surveillance requirements may be performed . The proposed changes are consistent with the MODE restrictions in NUREG-1433.

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

Signification Hazards Consideration
SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed changes remove the references to specific ASTM standards from the Administrative Controls Section of the Technical Specifications (TS) and place them in a licensee controlled document. Requirements to perform testing in accordance with the applicable ASTM standards is retained in the TS as are requirements to perform testing of both new and stored diesel fuel oil. Future changes to the licensee controlled document will be evaluated pursuant to the requirements of 10

CFR 50.59 to ensure that these changes do not result in more than a minimal increase in the probability or consequences of an accident previously evaluated. In addition, tests used to establish the acceptability of new fuel oil for use prior to and following the addition to storage tanks has been expanded to recognize more rigorous testing of water and sediment content.

Relocating the specific ASTM standard references from the TS to a licensee controlled document and allowing a water and sediment content test to be performed to establish the acceptability of new fuel oil will not affect nor degrade the ability of the emergency diesel generators (EDGs) to perform their specified safety function. Fuel oil quality will continue to be tested and maintained to ASTM requirements. Diesel fuel oil testing is not an initiator of any accident previously evaluated, and the proposed changes do not adversely affect any accident initiators or precursors, or alter design assumptions, conditions, and configuration of the facility, or the manner in which the plant is operated. The proposed changes do not adversely affect the ability of structures, systems, and components to perform their intended safety function to mitigate the consequences of an initiating event within the assumed acceptance limits. Therefore, the proposed changes do not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed changes remove the references to specific ASTM standards from the Administrative Controls Section of TS and place them in a licensee controlled document. In addition, the tests used to establish the acceptability of new fuel oil for use prior to and following the addition to storage tanks has been expanded to allow a water and sediment content test to be performed to establish the acceptability of new fuel oil. The changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed) or a change in the methods governing normal plant operation. The requirements retained in the TS will continue to require testing of new and stored diesel fuel oil to ensure the proper functioning of the EDGs. Therefore, the changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed changes remove the references to specific ASTM standards from the Administrative Controls Section of TS and place them in a licensee controlled document. Instituting the proposed changes will continue to ensure the use of applicable ASTM standards to evaluate the

quality of both new and stored fuel oil designated for use in the EDGs. Changes to the licensee-controlled document are performed in accordance with the provisions of 10 CFR 50.59. This approach provides an effective level of regulatory control and ensures that diesel fuel oil testing is conducted such that there is no significant reduction in a margin of safety. The margin of safety provided by the EDGs is unaffected by the proposed changes since TS requirements will continue to ensure fuel oil is of the appropriate quality. The proposed changes provide the flexibility needed to improve fuel oil sampling and analysis methodologies while maintaining sufficient controls to preserve the current margins of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.17 TSTF-400-A, Revision 1, "Clarify SR on Bypass of DG Automatic Trips"

Description of Proposed Change
The proposed change revises Specification 3.8.1, "AC Sources – Operating," Surveillance 3.8.1.11, to clarify that the intent of the SR is to test the non-critical emergency DG automatic trips.

Differences Between the Proposed Change and the Approved Traveler
The numbering of SRs in the Hatch Technical Specifications is different from the ISTS numbering. ISTS SR 3.8.1.13 corresponds to SR 3.8.1.11 in the Hatch TS. This has no effect on the requested change.

Summary of the Approved Traveler Justification
Branch Technical Position (BTP) ICSB-17, "Diesel Generator Protective Trip Circuit Bypasses," was replaced in 1981 by Regulatory Guide 1.9, Revision 2 (December 1979), Position C.7. Regulatory Guide 1.9, Rev. 3, Position C.1.8, is essentially unchanged from the 1979 position. The Regulatory Guide only requires verification that the non-critical trips are bypassed, and does not require verification that the critical trips are not bypassed. Regulatory Guide 1.9, Rev. 3, Section 2.2.12 states, "Protective Trip Bypass Test: Demonstrate that all automatic diesel generator trips (except engine overspeed, generator differential, and those retained with coincidental logic) are automatically bypassed on an SIAS." The BTP also states that if bypasses of non-critical emergency DG trips are used in the emergency DG design, "the design of the bypass circuitry should include the capability for testing the status and operability of the bypass circuits."

This BTP requirement is the source of ISTS SR 3.8.1.13, and it was intended that this SR would verify that the non-critical trips are bypassed so that a spurious actuation of a noncritical trip does not take an emergency DG out of service during an emergency. However, as the SR and Bases are currently written, it is implied that it is not only necessary to verify that the non-critical emergency DG trip bypasses are operable, but to verify the critical emergency DG trip channels are not bypassed. SR 3.8.1.11 and the associated Bases are revised to clarify the purpose of the SR. Testing to verify that critical emergency DG trips are not bypassed is not required to satisfy the requirements of 10 CFR 50.36(c)(3).

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
A listing of the non-critical and critical emergency diesel engine protection functions is provided in FSAR Tables 8.4-7 (Unit 1) and 8.3-9 (Unit 2). A listing of the non-critical and critical generator protection functions is provided in FSAR Tables 8.4-8 (Unit 1) and 8.3-10 (Unit 2).

A statement will be added to the FSAR similar to the following regarding the performance of logic testing for critical emergency DG trip functions:

> "The critical emergency diesel generator protective trip functions (i.e., engine overspeed, generator differential current, and low lube oil

pressure) are tested periodically per station procedures. The critical protective trip functions are tested by inputting or simulating appropriate signals and demonstrating that the associated instrumentation logic will function to actuate a trip of the emergency diesel generator."

NRC Approval
The NRC documented their approval of TSTF-400-A, Revision 1, in a letter from Thomas H. Boyce (NRC) to the Technical Specification Task Force dated November 13, 2004 (ACN ML043200067). An example of a plant-specific NRC approval of the changes in TSTF-400-A, Revision 1 is Peach Bottom Atomic Power Station, Units 2 and 3, Amendment Numbers 275/279, dated April 30, 2010 (ACN ML100900319).

List of Affected Pages
Unit 1
3.8-14
B3.8-29

Unit 2
3.8-14
B3.8-29

Applicable Regulatory Requirements/Criteria
Appendix A to Title 10 of the Code of Federal Regulations (10 CFR), Part 50, "General Design Criteria for Nuclear Power Plants," contains the following pertinent criteria:

Criterion 17, Electric Power Systems, states:

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power

supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

HNP Unit 1 Equivalent: 1967 GDC Criteria:

1967 GDC Criterion 24, Emergency Power for Protection Systems, states:
In the event of loss of all offsite power, sufficient alternate sources of power shall be provided to permit the required functioning of the protection systems.

1967 GDC Criterion 39, Emergency Power for Engineered Safety Features, states:
Alternate power systems shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite power system and the offsite power system shall each, independently, provide this capacity assuming a failure of a single active component in each power system.

Title 10 of the Code of Federal Regulations (10 CFR), Part 50, paragraph 36(c)(3), "Surveillance Requirements," states:
Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

The proposed changes clarify the intent of SR 3.8.1.11 and the associated Bases to state that the SR only verifies that non-critical emergency DG trips are bypassed. The non-critical emergency DG trips are designed to be bypassed during DBAs and provide an alarm on an abnormal engine condition. Testing to verify that critical emergency DG trips are not bypassed is not required to satisfy design requirements or the requirements of 10 CFR 50.36(c)(3). The changes are editorial, providing clarification, and no Technical Specification requirements are materially altered. The proposed changes are consistent with NUREG-1433.

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

Significant Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   This change clarifies the purpose of Surveillance Requirement (SR) 3.8.1.11, which is to verify that non-critical automatic emergency diesel generator (DG) trips are bypassed in an accident. The non-critical automatic DG trips and their bypasses are not initiators of any accident previously evaluated. Therefore, the probability of any accident is not significantly increased. Additionally, the function of the emergency DG in mitigating accidents is not changed. The revised SR continues to ensure the emergency DG will operate as assumed in the accident analysis. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

   Response: No.

   This change clarifies the purpose of SR 3.8.1.11, which is to verify that non-critical automatic emergency DG trips are bypassed in an accident. The proposed change does not involve a physical alteration of the plant (no new or different type of equipment will be installed), or a change in the methods governing normal plant operation. Thus, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   This change clarifies the purpose of SR 3.8.1.11, which is to verify that non-critical automatic DG trips are bypassed in an accident. This change clarifies the purpose of the SR, which is to verify that the emergency DG is capable of performing the assumed safety function. The safety function of the emergency DG is unaffected, so the change does not affect the margin of safety. Therefore, this change does not involve a significant reduction in a margin of safety.

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

2.18 TSTF-439-A, Revision 2, "Eliminate Second Completion Times Limiting Time From Discovery of Failure To Meet an LCO"

Description of Proposed Change
Specifications 3.1.7, "Standby Liquid Control (SLC) System;" 3.6.4.3, "Standby Gas Treatment (SGT) System;" 3.8.1, "AC Sources - Operating;" and 3.8.7, "Distribution Systems - Operating," contain Required Actions with a second Completion Time to establish a limit on the maximum time allowed for any combination of Conditions that result in a single continuous failure to meet the LCO. These Completion Times (henceforth referred to as "second Completion Times") are joined by an "AND" logical connector to the Condition-specific Completion Time and state "X days from discovery of failure to meet the LCO" (where "X" varies by specification). The proposed change deletes these second Completion Times from the affected Required Actions. It also revises ISTS Example 1.3-3 to remove the discussion of second Completion Times and to revise the discussion in that Example to state that alternating between Conditions in such a manner that operation could continue indefinitely without restoring systems to meet the LCO is inconsistent with the basis of the Completion Times and is inappropriate. Therefore, the licensee shall have administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO.

Differences Between the Proposed Change and the Approved Traveler
ISTS Specification 3.8.9, "Distribution Systems - Operating," is equivalent to Hatch Specification 3.8.7, "Distribution Systems - Operating."

In addition to the specifications affected by TSTF-439-A, Hatch Specification 3.6.4.3, "Standby Gas Treatment (SGT) System," contains a second Completion Time for Required Action B.1. The same justification presented for the other second Completion Times applies to this Completion Time. Therefore, it is also removed. The associated Bases do not require revision as the second Completion Time is not discussed.

Summary of the Approved Traveler Justification
The proposed change adopts a new technical specification convention to limit the maximum time allowed for any combination of LCO Conditions that could result in a single continuous failure to meet the LCO. In the current Technical Specifications, a second Completion Time was included for certain Required Actions to establish a limit on the maximum time allowed for any combination of Conditions that would result in a single continuous failure to meet the LCO. In practice, the addition of second Completion Times did not create an operational restriction because the likelihood of experiencing concurrent failures such that the second Completion Time was limiting is remote. It is important to note that this issue of "flip flopping" between Conditions only applies if the LCO is not met on a continuous basis. In addition, if the LCO requirements are met, even if for an instant, this issue does not occur.

The second Completion Times created a problem when the industry and the NRC developed and approved Technical Specification changes that integrated risk-informed Completion Times into specifications containing a second Completion Time. The problem results from extending the second Completion Time by the

same amount (i.e., the second Completion Time continued to be the sum of the two Completion Times.) The NRC staff expressed concerns that the extension of the second Completion Time was inappropriate because one of the two Completion Times added to obtain the second Completion Time limit was risk-based and the other was derived in a deterministic evaluation. The NRC eventually accepted the practice of adding the deterministic and risk-informed Completion Times, but it continues to result in confusion.

An alternative approach was proposed and accepted by the NRC that eliminated the second Completion Times and modified Section 1.3 of the Technical Specifications to establish a convention prohibiting alternating between Conditions in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. Thus, there is no longer a specific limit to the maximum time allowed for any combination of Conditions that result in a single continuous occurrence of failing to meet the LCO.

The proposed change is appropriate because multiple continuous entries into Conditions, without meeting the LCO, will be controlled by licensee's configuration risk management programs, which were implemented to meet the requirements 10 CFR 50.65 (the maintenance rule) to assess and manage risk, and controlled by the Use and Application convention discussed in Section 1.3 of the Technical Specifications. These controls provide adequate assurance against inappropriate use of combinations of Conditions that result in a single contiguous occurrence of failing to meet the LCO.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification

TSTF-439-A revises Example 1.3-3 of the Technical Specifications to state, in part, "there shall be administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls shall ensure that the Completion Times for those Conditions are not inappropriately extended." The NRC has asked licensees adopting TSTF-439-A to provide the location of these administrative controls. As described in the section, "Licensee Commitments Required to Adopt this Change," SNC commits to revise Operations procedure 31GO-OPS-006-0 to include these administrative controls.

Licensee Commitments Required to Adopt this Change

SNC commits to revise Operations procedure 31GO-OPS-006-0 to include a statement similar to the following: "Alternating between LCO Conditions, in order to allow indefinite continued operation while not meeting the LCO, is not allowed." This procedure will be revised prior to implementation of the proposed change.

NRC Approval

The NRC documented their approval of TSTF-439-A, Revision 2 in a letter from Thomas Boyce (NRC) to the Technical Specification Task Force date January 11, 2006 (ACN ML060120272). TSTF-439-A, Revision 2, was also incorporated into the ISTS NUREGs. An example of a plant-specific NRC approval of the changes in TSTF-439-A, Revision 2 is Calvert Cliffs Nuclear Power Plant, Units 1 and 2, Amendment Numbers 304/282, dated January 29, 2014 (ACN ML14009A320).

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Applicable Regulatory Requirements/Criteria

Title 10 of the Code of Federal Regulations (10 CFR), 10 CFR 50.36(c)(2), states:

> Limiting conditions for operation. (i) Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.

There is no regulatory requirement that specifies what remedial actions are to be taken when a limiting condition for operation is not met. The proposed change

makes the remedial actions consistent with safety significance of the condition. The proposed changes are consistent with NUREG-1433.

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

Significant Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change eliminates certain Completion Times from the Technical Specifications. Completion Times are not an initiator to any accident previously evaluated. As a result, the probability of an accident previously evaluated is not affected. The consequences of an accident during the remaining Completion Time are no different than the consequences of the same accident during the removed Completion Times. As a result, the consequences of an accident previously evaluated are not affected by this change. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change to delete the second Completion Time does not alter the manner in which safety limits, limiting safety system settings or limiting conditions for operation are determined. The safety analysis

acceptance criteria are not affected by this change. The proposed changes will not result in plant operation in a configuration outside of the design basis. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.19 TSTF-458-T, Revision 0, "Removing Restart of Shutdown Clock for Increasing Suppression Pool Temperature"

Description of Proposed Change
The proposed change revises Specification 3.6.2.1, "Suppression Pool Average Temperature," Required Actions D and E, to eliminate redundant requirements.

Differences Between the Proposed Change and the Approved Traveler
None

Summary of the Approved Traveler Justification
Specification 3.6.2.1, Actions D and E both require the plant to be in Mode 4 within 36 hours. Action D is entered when the suppression pool average temperature is > 100°F but ≤ 120°F. Action E is entered when the suppression pool average temperature is > 120°F. This change revises the entry condition for Action D to "suppression pool average temperature > 110 °F" and removes the "Be in MODE 4" Required Action from Action E. This eliminates having two Required Actions and Completion Times, both directing entry into Mode 4, with staggered Completion Times.

Specification 3.6.2.1, Actions D and E, currently allow a resetting of the shutdown requirement ("Be in MODE 4 within 36 hours") when the suppression pool average temperature rises above 120°F. This occurs because the Condition of Action D is no longer met when temperature exceeds 120°F and, therefore, the Required Actions are no longer applicable. The entry conditions of Action E are met when temperature exceeds 120°F and a new Completion Time clock begins for Action E. If temperature drops below 120°F, Condition E no longer applies and the Completion Time clock of Condition D is restarted at zero.

The current construction of the Actions is inconsistent with the intent to promptly bring the reactor to a condition in which the LCO does not apply. Removing the upper limit of the entry condition for Action D would require the shutdown Required Action of Condition D to continue to be applicable if temperature increases above 120°F. Action E would also be applicable and require the reactor vessel to be depressurized below 200 psig within 12 hours.

Required Action D.2 is changed from "Verify suppression pool average temperature is ≤ 120°F" to "Determine suppression pool average temperature" since Required Action D.2 would continue to apply when the temperature is > 120°F.

A similar change is not needed for Action A since Action B provides the appropriate default actions for noncompliance with Required Action A.1.

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
TSTF-458-T, Revision 0, is a "T" or "template" Traveler that was reviewed and approved by the Technical Specification Task Force but was not submitted to the NRC for review and approval.

The proposed change was incorporated in the Monticello ITS conversion amendment, submitted to the NRC on June 25, 2005 (ACN ML051960175). The Monticello ITS conversion was approved on June 5, 2006 as Amendment Number 146 (ACN ML061240241).

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Applicable Regulatory Requirements/Criteria
Title 10 of the Code of Federal Regulations (10 CFR), 10 CFR 50.36(c)(2), states:

> Limiting conditions for operation. (i) Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.

There is no regulatory requirement that specifies what remedial actions are to be taken when a limiting condition for operation is not met. The proposed changes are consistent with NUREG-1433.

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

Significant Hazards Consideration
SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

The proposed change revises Specification 3.6.2.1, "Suppression Pool Average Temperature," Required Actions D and E, to eliminate redundant requirements when suppression pool temperature is above the Limiting Conditions for Operation (LCO) limit. Suppression pool temperature is not an initiator to any accident previously evaluated. Suppression pool temperature may affect the mitigation of accidents previously evaluated. The proposed change reduces the time allowed to operate with suppression pool temperature above the limit. The consequences of an accident under the proposed change are no different than under the current requirements. Therefore, the proposed change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change revises Specification 3.6.2.1, "Suppression Pool Average Temperature," Required Actions D and E, to eliminate redundant requirements when suppression pool temperature is above the LCO limit. The proposed change reduces the time allowed to operate with suppression pool temperature above the limit. The proposed revision will not adversely affect the margin of safety as it corrects the Actions to provide appropriate compensatory measures when suppression pool temperature is greater than the limit. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

2.20 TSTF-464-T, Revision 0, "Clarify the Control Rod Block Instrumentation Required Action"

Description of Proposed Change
The proposed change revises Specification 3.3.2.1, Required Action C.2.1.2 from "Verify by administrative methods that startup with RWM inoperable has not been performed in the last calendar year" to "Verify by administrative methods that startup with RWM inoperable has not been performed in the last 12 months."

Summary of the Approved Traveler Justification
With the Rod Worth Minimizer (RWM) inoperable during a reactor startup, the operator is still capable of enforcing the prescribed control rod sequence. However, overall reliability is reduced because a single operator error can result in violating the control rod sequence. Therefore, control rod movement must be immediately suspended except by scram when the RWM is not operable. Alternatively, startup may continue if at least 12 control rods have already been withdrawn, or a reactor startup with an inoperable RWM was not performed in the last 12 months. The purpose of the 12 month restriction is to enforce infrequent occurrences of reactor startup with the RWM inoperable.

Technical Specification 3.3.2.1, Control Rod Block Instrumentation, Required Action C.2.1.2, requires verification by administrative means that startup with the RWM inoperable has not been performed in the last calendar year. The Bases for Required Action C.2.1.2 states that verification is required that a reactor startup with an inoperable RWM was not performed in the last 12 months. The wording in the Required Action 3.3.2.1 is ambiguous because it can be interpreted as the preceding 12 months (current date - 12 months) or the last year (January through December). The Bases wording, "last 12 months," is unambiguous and is adopted in the Specification. This change revises the Technical Specification to be consistent with the Bases, thereby clarifying the intent of Required Action C.2.1.2.

Differences Between the Proposed Change and the Approved Traveler
None

Differences Between the Plant-Specific Justification and the Approved Traveler Justification
None

Licensee Commitments Required to Adopt this Change
None

NRC Approval
TSTF-464-T, Revision 0, is a "T" or "template" Traveler that was reviewed and approved by the Technical Specification Task Force but was not submitted to the NRC for review and approval.

The proposed change was incorporated in the Monticello ITS conversion amendment, submitted to the NRC on June 25, 2005 (ACN ML051960175). The Monticello ITS conversion was approved on June 5, 2006 as Amendment Number 146 (ACN ML061240241). The Monticello amendment noted the same

change had been approved by the NRC for Quad Cities 1 and 2, Dresden 2 and 3, and LaSalle 1 and 2.

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3.3-16

Applicable Regulatory Requirements/Criteria
Title 10 of the Code of Federal Regulations (10 CFR), Part 50, paragraph 36(c)(3), "Surveillance Requirements," states:

> Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

There is no regulatory requirement that specifies the frequency of performing Surveillance Requirements.

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

Significant Hazards Consideration
SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change revises a Required Action to limit startup with the Rod Worth Minimizer (RWM) inoperable from once per calendar year to once per 12 months. The RWM is used to minimize the possibility and consequences of a control rod drop accident. This change clarifies the intent of the limitation, but does not affect the requirement for the RWM to be operable. As, over time, the number of startups with the RWM inoperable will not increase, the probability of any accident previously evaluated is not significantly increased. As the RWM is still required to be operable, the consequences of an 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. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   The proposed change revises a Required Action to limit startup with the Rod Worth Minimizer inoperable from once per calendar year to once per 12 months. No new or different accidents result from utilizing the proposed change. The changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed) or a significant change in the methods governing normal plant operation. The changes do not alter assumptions made in the safety analysis. The proposed changes are 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. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.

   The proposed change revises a Required Action to limit startup with the Rod Worth Minimizer (RWM) inoperable from once per calendar year to once per 12 months. This clarifies the intent of the Required Action. The number of startups with RWM inoperable is not increased. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

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

2.21 ISTS Adoption #1 - Revise the 5.5.7 Introductory Paragraph to be Consistent with the ISTS

Description of Proposed Change
The proposed change revises the introductory paragraph of Specification 5.5.7, "Ventilation Filter Testing Program (VFTP)," to be consistent with the ISTS. Specific requirements to perform testing after structural maintenance on the HEPA filter or charcoal adsorber housing or following painting, fire or chemical release, and after every 720 hours of operation are relocated to the licensee-controlled program.

The existing wording states, "The VFTP will establish the required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2, Sections C.5.c and C.5.d, or: 1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, 2) following painting, fire or chemical release in any ventilation zone communicating with the system, or 3) after every 720 hours of charcoal adsorber operation."

The proposed wording states, " A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2, Sections C.5.c and C.5.d, and in accordance with Regulatory Guide 1.52, Revision 2."

Differences Between the Proposed Change and the ISTS
None

Summary of the ISTS Justification
Regulatory Guide 1.52, Revision 2, Regulatory Position 6.b, states that testing should be performed (1) initially, (2) at least once per 18 months thereafter for systems maintained in a standby status or after 720 hours of system operation, and (3) following painting, fire, or chemical release in any ventilation zone communicating with the system. Therefore, items 2 and 3 of the existing introductory paragraph are retained as a reference to the Regulatory Guide instead of being explicitly stated. The VFTP testing is required by Chapter 3 Surveillance Requirements. SR 3.0.1 requires Surveillance Requirements to be met "during the performance of the Surveillance or between performances of the Surveillance." The SR 3.0.1 Bases explain this requirement and state, "Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2." Therefore, item 1 of the existing introductory paragraph is retained as a Technical Specifications requirement.

The removal of these details for performing surveillance requirements from the introductory paragraph of the VFTP is acceptable because this type of information is not necessary to be included in the Technical Specifications to provide adequate protection of public health and safety. The Technical Specifications still retain the requirements to perform tests on the ventilation filters in a manner consistent with Regulatory Positions Regulatory Guide 1.52,

Revision 2 and SR 3.0.1. Also, this change is acceptable because these types of procedural details will be adequately controlled in VFTP. The VFTP will be maintained in accordance with 10 CFR 50.59. This change is designated as a less restrictive removal of detail change because procedural details for meeting Technical Specification requirements are being removed from the Technical Specifications.

Differences Between the Plant-Specific Justification and the ISTS Justification

Licensee Commitments Required to Adopt this Change

The Hatch license amendment request to convert to the ISTS did not adopt the ISTS introductory paragraph for the VFTP. The justification given stated, "Existing Plant Hatch requirements for ventilation filter testing are used in place of the NUREG wording. The NUREG requirements are retained along with more specific language for frequency of testing." In order to increase the consistency between the Hatch Technical Specifications, the ISTS, and the other SNC fleet plant Technical Specifications, the ISTS wording is being adopted.

NRC Approval

The ISTS has provided the same introductory paragraph for the Ventilation Filter Test Program since Revision 0 of the ISTS was issued in 1992. Plant specific examples of the adoption of the VFTP introductory paragraph are the Vogtle and Farley Technical Specifications.

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Applicable Regulatory Requirements/Criteria

Title 10 of the Code of Federal Regulations (10 CFR), Part 50, paragraph 36(c)(5), "Administrative Controls," states:

> Administrative controls are the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner. Each licensee shall submit any reports to the Commission pursuant to approved technical specifications as specified in § 50.4.

The proposed change is consistent with the requirements of 10 CFR 50.36 and is consistent with NUREG-1433.

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

Significant Hazards Consideration

SNC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change revises the introductory paragraph of Specification 5.5.7, "Ventilation Filter Testing Program (VFTP)," to be consistent with the ISTS. Specific requirements to perform testing after structural maintenance on the HEPA filter or charcoal adsorber housing or following painting, fire or chemical release, and after every 720 hours of operation are retained as a reference to Regulatory Guide requirements and general requirements in Surveillance Requirement (SR) 3.0.1. Implementation of these requirements will be in the licensee-controlled VFTP. The VFTP will be maintained in accordance with 10 CFR 50.59. Since any changes to the VFTP will be evaluated under 10 CFR 50.59, no significant increase in the probability or consequences of an accident previously evaluated will be allowed. Therefore, this proposed change does not represent a significant increase in the probability or consequences of an accident previously evaluated.

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

   Response: No.

   The proposed change does not involve a physical alteration to the plant (i.e., no new or different type of equipment will be installed) or a change to the methods governing normal plant operation. The changes do not alter the assumptions made in the safety analysis. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   The proposed change revises the introductory paragraph of Specification 5.5.7, "Ventilation Filter Testing Program (VFTP)," to be consistent with the ISTS. The proposed change will not reduce a margin of safety because it has no effect on any safety analysis assumption. In addition, no requirements are being removed, but are being replaced with references to an NRC Regulatory Guide and the requirements of SR 3.0.1. Therefore, this proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

3.0 Environmental Considerations

SNC has reviewed the proposed changes pursuant to 10 CFR 50.92 and determined that it does not involve a significant hazards consideration. In addition, there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite, and there is no significant increase in individual or cumulative occupational radiation exposure. Consequently, the proposed Technical Specifications changes have no significant effect on the human environment and satisfy the criteria of 10 CFR 51.22 for categorical exclusion from the requirements for an environmental assessment.

Edwin I. Hatch Nuclear Plant
Request for Technical Specifications Amendment
Adoption of Generic Technical Specification Changes

Enclosure 2

Marked-Up Technical Specifications Pages

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No change. Included for information only.

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE

The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.

BACKGROUND

Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).

DESCRIPTION

The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the LCO Applicability.

If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition.

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 <u>not</u> result in separate entry into the Condition unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

However, when a <u>subsequent</u> division, subsystem, component, or variable expressed in the Condition is discovered to be inoperable or not within limits, the Completion Time(s) may be extended. To apply this Completion Time extension, two criteria must first be met. The subsequent inoperability:

(continued)

1.3 Completion Times

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DESCRIPTION (continued)

a. Must exist concurrent with the first inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extension does not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each division, subsystem, component or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase "from discovery . . ." ~~Example 1.3-3 illustrates one use of this type of Completion Time. The 10 day Completion Time specified for Conditions A and B in Example 1.3-3 may not be extended.~~

(continued)

1.3 Completion Times

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EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X subsystem inoperable.	A.1 Restore Function X subsystem to OPERABLE status.	7 days ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
B. One Function Y subsystem inoperable.	B.1 Restore Function Y subsystem to OPERABLE status.	72 hours ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
C. One Function X subsystem inoperable. AND One Function Y subsystem inoperable.	C.1 Restore Function X subsystem to OPERABLE status. OR C.2 Restore Function Y subsystem to OPERABLE status.	72 hours 72 hours

(continued)

1.3 Completion Times

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EXAMPLES

EXAMPLE 1.3-3 (continued)

When one Function X subsystem and one Function Y subsystem are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each subsystem, starting from the time each subsystem was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second subsystem was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected subsystem was declared inoperable (i.e., initial entry into Condition A).

~~The Completion Times of Conditions A and B are modified by a logical connector, with a separate 10 day Completion Time measured from the time it was discovered the LCO was not met. In this example, without the separate Completion Time, it would be possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. The separate Completion Time modified by the phrase "from discovery of failure to meet the LCO" is designed to prevent indefinite continued operation while not meeting the LCO. This Completion Time allows for an exception to the normal "time zero" for beginning the Completion Time "clock." In this instance, the Completion Time "time zero" is specified as commencing at the time the LCO was initially not met, instead of at the time the associated Condition was entered.~~

INSERT - TS 1.3 Example

(continued)

Insert – TS 1.3 Example

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It is possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. However, doing so would be inconsistent with the basis of the Completion Times. Therefore, there shall be administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls shall ensure that the Completion Times for those Conditions are not inappropriately extended.

1.0 USE AND APPLICATION

1.4 Frequency

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PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated Limiting Conditions for Operation (LCO). An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR, as well as certain Notes in the Surveillance column that modify performance requirements.

Sometimes special situations dictate when the requirements of a Surveillance are to be met. They are "otherwise stated" conditions allowed by SR 3.0.1. They may be stated as clarifying Notes in the Surveillance, as part of the Surveillance, or both. ~~Example 1.4-4 discusses these special situations.~~

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

The use of "met" or "performed" in these instances conveys specific meanings. A Surveillance is "met" only when the acceptance criteria are satisfied. Known failure of the requirements of a Surveillance, even without a Surveillance specifically being "performed," constitutes a Surveillance not "met." "Performance" refers only to the requirement to specifically determine the ability to meet the acceptance criteria.

INSERT - TS 1.4 Description → ~~SR 3.0.4 restrictions would not apply if both the following conditions are satisfied:~~

(continued)

Insert – TS 1.4 Description

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Some Surveillances contain notes that modify the Frequency of performance or the conditions during which the acceptance criteria must be satisfied. For these Surveillances, the MODE-entry restrictions of SR 3.0.4 may not apply. Such a Surveillance is not required to be performed prior to entering a MODE or other specified condition in the Applicability of the associated LCO if any of the following three conditions are satisfied:

a. The Surveillance is not required to be met in the MODE or other specified condition to be entered; or

b. The Surveillance is required to be met in the MODE or other specified condition to be entered, but has been performed within the specified Frequency (i.e., it is current) and is known not to be failed; or

c. The Surveillance is required to be met, but not performed, in the MODE or other specified condition to be entered, and is known not to be failed.

Examples 1.4-3, 1.4-4, 1.4-5, and 1.4-6 discusses these special situations.

1.4 Frequency

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DESCRIPTION (continued)

~~a. The Surveillance is not required to be performed; and~~

~~b. The Surveillance is not required to be met or, even if required to be met, is not known to be failed~~.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the interval specified in the Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Examples 1.4-3 and 1.4-4), then SR 3.0.3 becomes applicable.

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, then SR 3.0.4 becomes applicable. The Surveillance must be performed within the Frequency requirements of SR 3.0.2, as modified by SR 3.0.3, prior to entry into the mode or other specified condition or the LCO is considered not met (in accordance with SR 3.0.1) and LCO 3.0.4 becomes applicable.

(continued)

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EXAMPLES (continued)

EXAMPLE 1.4-4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Only required to be met in MODE 1. ----------	
Verify leakage rates are within limits.	24 hours

Example 1.4-4 specifies that the requirements of this Surveillance do not have to be met until the unit is in MODE 1. The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour (plus the extension allowed by SR 3.0.2) interval, but the unit was not in MODE 1, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES, even with the 24 hour Frequency exceeded, provided the MODE change was not made into MODE 1. Prior to entering MODE 1 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

INSERT - TS 1.4 Example 1.4-5

INSERT - TS 1.4 Example 1.4-6

Insert – TS 1.4 Example 1.4-5

EXAMPLE 1.4-5

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Only required to be performed in MODE 1. ----------	
Perform complete cycle of the valve.	7 days

The interval continues, whether or not the unit operation is in MODE 1, 2, or 3 (the assumed Applicability of the associated LCO) between performances.

As the Note modifies the required performance of the Surveillance, the Note is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is not in MODE 1, this Note allows entry into and operation in MODES 2 and 3 to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency" if completed prior to entering MODE 1. Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was not in MODE 1, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not result in entry into MODE 1.

Once the unit reaches MODE 1, the requirement for the Surveillance to be performed within its specified Frequency applies and would require that the Surveillance had been performed. If the Surveillance were not performed prior to entering MODE 1, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

Insert – TS 1.4 Example 1.4-6

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EXAMPLE 1.4-6

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Not required to be met in MODE 3. ----------	
Verify parameter is within limits.	24 hours

Example 1.4-6 specifies that the requirements of this Surveillance do not have to be met while the unit is in MODE 3 (the assumed Applicability of the associated LCO is MODES 1, 2, and 3). The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), and the unit was in MODE 3, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES to enter MODE 3, even with the 24 hour Frequency exceeded, provided the MODE change does not result in entry into MODE 2. Prior to entering MODE 2 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

SURVEILLANCE REQUIREMENTS

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----------NOTE----------
During single control rod scram time Surveillances, the control rod drive (CRD) pumps shall be isolated from the associated scram accumulator.

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify each 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 reactor pressure vessel~~ ~~AND~~ Prior to exceeding 40% RTP after each reactor shutdown ≥ 120 days
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 exceeding 40% RTP after fuel movement within the affected fuel cell AND	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 work on control rod or CRD System that could affect scram time

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3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Sodium pentaborate solution not within Region A limits of Figure 3.1.7-1 or 3.1.7-2, but within the Region B limits.	A.1 Restore sodium pentaborate solution to within Region A limits.	72 hours ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
B. One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	7 days ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1 Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	12 hours

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.2	----------NOTE---------- Not required to be performed until 12 hours after THERMAL POWER ≥ 24% RTP. ---------- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 24% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.3	(Not used.)	
SR 3.3.1.1.4	----------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 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.6 (Not used.)	~~Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap~~.	~~Prior to withdrawing SRMs from the fully inserted position~~

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.7 (Not used.)	~~----------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 3.3.1.1.8	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	----------NOTE---------- 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 FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.11	Verify Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 27.6% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

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FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitor					
a. Neutron Flux - High	2	2[d]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 ~~SR 3.3.1.1.6~~ ~~SR 3.3.1.1.7~~ SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
	5[a]	2[d]	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
b. Inop	2	2[d]	G	SR 3.3.1.1.4 SR 3.3.1.1.15	NA
	5[a]	2[d]	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
2. Average Power Range Monitor					
a. Neutron Flux - High (Setdown)	2	3[c]	G	SR 3.3.1.1.1 ~~SR 3.3.1.1.7~~ SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 20% RTP
b. Simulated Thermal Power - High	1	3[c]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 0.57W + 56.8% RTP and ≤ 115.5% RTP[b]
c. Neutron Flux - High	1	3[c]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 120% RTP
d. Inop	1, 2	3[c]	G	SR 3.3.1.1.10	NA

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) 0.57W + 56.8% - 0.57 ΔW RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) Each APRM channel provides inputs to both trip systems.

(d) One channel in each quadrant of the core must be OPERABLE whenever the IRMs are required to be OPERABLE. Both the RWM and a second licensed operator must verify compliance with the withdrawal sequence when less than three channels in any trip system are OPERABLE.

No change. Included for information only.

3.3 INSTRUMENTATION

3.3.2.1 Control Rod Block Instrumentation

LCO 3.3.2.1 The control rod block instrumentation for each Function in Table 3.3.2.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2.1-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One rod block monitor (RBM) channel inoperable.	A.1 Restore RBM channel to OPERABLE status.	24 hours
B. Required Action and associated Completion Time of Condition A not met. OR Two RBM channels inoperable.	B.1 Place one RBM channel in trip.	1 hour
C. Rod worth minimizer (RWM) inoperable during reactor startup.	C.1 Suspend control rod movement except by scram. OR C.2.1.1 Verify ≥ 12 rods withdrawn. OR	Immediately Immediately

(continued)

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ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.1.2 Verify by administrative methods that startup with RWM inoperable has not been performed in the last ~~calendar year~~ 12 months.	Immediately
	AND	
	C.2.2 Verify movement of control rods is in compliance with banked position withdrawal sequence (BPWS) by a second licensed operator or other qualified member of the technical staff.	During control rod movement
D. RWM inoperable during reactor shutdown.	D.1 Verify movement of control rods is in compliance with BPWS by a second licensed operator or other qualified member of the technical staff.	During control rod movement
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

Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

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	FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1
1.	Reactor Steam Dome Pressure	2	E
2.	Reactor Vessel Water Level		
	a. -317 inches to -17 inches	2	E
	b. -150 inches to +60 inches	2	E
	c. 0 inches to +60 inches	2	E
	d. 0 inches to +400 inches	1	NA
3.	Suppression Pool Water Level		
	a. 0 inches to 300 inches	2	E
	b. 133 inches to 163 inches	2	E
4.	Drywell Pressure		
	a. -10 psig to +90 psig	2	E
	b. -5 psig to +5 psig	2	E
	c. 0 psig to +250 psig	2	E
5.	Drywell Area Radiation (High Range)	2	F
6.	Primary Containment Isolation Valve Position Penetration Flow Path	2 per penetration flow path (a)(b)	E
7.	(Deleted)		
8.	(Deleted)		
9.	Suppression Pool Water Temperature	2(c)	E
10.	Drywell Temperature in Vicinity of Reactor Level Instrument Reference Leg	6	E
11.	Diesel Generator (DG) Parameters		
	a. Output Voltage	1 per DG	NA
	b. Output Current	1 per DG	NA
	c. Output Power	1 per DG	NA
	d. Battery Voltage	1 per DG	NA
12.	RHR Service Water Flow	2	E

(a) Not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Monitoring each of four quadrants.

3.3 INSTRUMENTATION

TSTF-306

3.3.6.1 Primary Containment Isolation Instrumentation

LCO 3.3.6.1 The primary containment isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

1. Penetration flow paths may be unisolated intermittently under administrative controls.

~~NOTE~~

2. Separate Condition entry is allowed for each channel.

NOTES

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	12 hours for Functions 2.a, 2.b, ~~and~~ 6.b, 7.a, and 7.b AND 24 hours for Functions other than Functions 2.a, 2.b, ~~and~~ 6.b, 7.a, and 7.b
B. ----------NOTE---------- Not applicable for Function 5.c. ---------- One or more automatic Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	D.1 Isolate associated main steam line (MSL). OR D.2.1 Be in MODE 3. AND D.2.2 Be in MODE 4.	12 hours 12 hours 36 hours
E. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	E.1 Be in MODE 2.	6 hours
F. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	F.1 Isolate the affected penetration flow path(s).	1 hour
H. ~~G.~~ As required by Required Action C.1 and referenced in Table 3.3.6.1-1. OR Required Action and associated Completion Time of Condition F or G not met.	~~G.1~~ H.1 Be in MODE 3. AND ~~G.2~~ H.2 Be in MODE 4.	12 hours 36 hours
I. ~~H.~~ As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	~~H.1~~ I.1 Declare Standby Liquid Control (SLC) System inoperable. OR ~~H.2~~ I.2 Isolate the Reactor Water Cleanup (RWCU) System.	1 hour 1 hour

INSERT - TS 3.3.6.1 Condition G

(continued)

INSERT - TS 3.3.6.1 Condition G

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G.	As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	G.1	Isolate the affected penetration flow path(s).	24 hours

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~I.~~ J. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	~~I.1~~ J.1 Initiate action to restore channel to OPERABLE status.	Immediately
	OR	
	~~I.2~~ J.2 Initiate action to isolate the Residual Heat Removal (RHR) Shutdown Cooling System.	Immediately

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

(continued)

Table 3.3.6.1-1 (page 1 of 4)
Primary Containment Isolation Instrumentation

TSTF-306

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level - Low Low Low, Level 1	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ -113 inches
b. Main Steam Line Pressure - Low	1	2	E	SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 825 psig
c. Main Steam Line Flow - High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 138% rated steam flow
d. Condenser Vacuum - Low	1, 2[a], 3[a]	2	D	SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 7 inches Hg vacuum
e. Main Steam Tunnel Temperature - High	1,2,3	6	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 194°F
f. Turbine Building Area Temperature - High	1,2,3	16[b]	D	SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 200°F
2. Primary Containment Isolation					
a. Reactor Vessel Water Level - Low, Level 3	1,2,3	2	H → ~~G~~	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches
b. Drywell Pressure - High	1,2,3	2	H → ~~G~~	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig

(continued)

(a) With any turbine stop valve not closed.

(b) With 8 channels per trip string. Each trip string shall have 2 channels per main steam line, with no more than 40 ft separating any two OPERABLE channels.

Table 3.3.6.1-1 (page 2 of 4)
Primary Containment Isolation Instrumentation

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FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Primary Containment Isolation (continued)					
c. Drywell Radiation - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 138 R/hr
d. Reactor Building Exhaust Radiation - High	1,2,3	2	~~G~~ H	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.6	≤ 80 mR/hr
e. Refueling Floor Exhaust Radiation - High	1,2,3	2	~~G~~ H	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.6	≤ 80 mR/hr
3. High Pressure Coolant Injection (HPCI) System Isolation					
a. HPCI Steam Line Flow - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 303% rated steam flow
b. HPCI Steam Supply Line Pressure - Low	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 100 psig
c. HPCI Turbine Exhaust Diaphragm Pressure - High	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 20 psig
d. Drywell Pressure - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig
e. HPCI Pipe Penetration Room Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
f. Suppression Pool Area Ambient Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F

(continued)

Table 3.3.6.1-1 (page 4 of 4)
Primary Containment Isolation Instrumentation

TSTF-306

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. RCIC System Isolation (continued)					
g. RCIC Suppression Pool Area Differential Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 42°F
h. Emergency Area Cooler Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
5. RWCU System Isolation					
a. Area Temperature - High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 150°F
b. Area Ventilation Differential Temperature - High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 67°F
c. SLC System Initiation	1,2	1(c)	I → H	SR 3.3.6.1.6	NA
d. Reactor Vessel Water Level - Low Low, Level 2	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ -47 inches
6. RHR Shutdown Cooling System Isolation					
a. Reactor Steam Dome Pressure - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 145 psig
b. Reactor Vessel Water Level - Low, Level 3	3,4,5	2 (d)	J → H	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches

← INSERT - TS Table 3.3.6.1-1

(c) SLC System Initiation only inputs into one of the two trip systems.

(d) Only one trip system required in MODES 4 and 5 when RHR Shutdown Cooling System integrity maintained.

INSERT – TS Table 3.3.6.1-1

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7. Traversing Incore Probe System Isolation					
a. Reactor Vessel Water Level - Low, Level 3	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches
b. Drywell Pressure - High	1, 2, 3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig

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3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.1 ECCS - Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of six of seven safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except high pressure coolant injection (HPCI) and ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig.

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to HPCI.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable.	A.1 Restore low pressure ECCS injection/spray ~~subsystem~~ subsystem(s) to OPERABLE status.	7 days
INSERT - TS 3.5.1 Condition A		
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours
C. HPCI System inoperable.	C.1 Verify by administrative means RCIC System is OPERABLE. AND C.2 Restore HPCI System to OPERABLE status.	1 hour 14 days

(continued)

INSERT – TS 3.5.1 Condition A

OR

One LPCI pump in both LPCI susbsystems inoperable.

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. HPCI System inoperable. AND ~~One low pressure ECCS injection/spray subsystem is inoperable.~~ Condition A entered.	D.1 Restore HPCI System to OPERABLE status. OR D.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours 72 hours
E. Two or more ADS valves inoperable. OR Required Action and associated Completion Time of Condition C or D not met.	E.1 Be in MODE 3. AND E.2 Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours
F. Two or more low pressure ECCS injection/spray subsystems inoperable. for reasons other than Condition A OR HPCI System and two or more ADS valves inoperable.	F.1 Enter LCO 3.0.3.	Immediately

No change. Included for information only.

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV, except reactor building-to-suppression chamber vacuum breakers, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation."

ACTIONS

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

1. Penetration flow paths except for 18 inch purge valve penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----------NOTE---------- Only applicable to penetration flow paths with two PCIVs. ---------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. AND	4 hours except for main steam line AND 8 hours for main steam line (continued)

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ACTIONS

NOTES

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued) 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means.	A.2 ----------NOTE---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside primary containment AND 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, for isolation devices inside primary containment
B. ----------NOTE---------- Only applicable to penetration flow paths with two PCIVs. ---------- One or more penetration flow paths with two PCIVs inoperable except due to leakage not within limit.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour

(continued)

and penetrations with a closed system

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ----------NOTE---------- Only applicable to penetration flow paths with only one PCIV. ---------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limits.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	4 hours except for excess flow check valve (EFCV) line AND ~~12 hours for EFCV line~~ 72 hours for EFCV line and penetrations with a closed system
	AND	
	C.2 ----------~~NOTE~~ NOTES ---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. ---------- 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means.	
	Verify the affected penetration flow path is isolated.	Once per 31 days
D. One or more penetration flow paths with leakage not within limit.	D.1 Restore leakage to within limit.	4 hours
E. Required Action and associated Completion Time of Condition A, B, C, or D not met in MODE 1, 2, or 3.	E.1 Be in MODE 3.	12 hours
	AND	
	E.2 Be in MODE 4.	36 hours

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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 is required to be closed during accident conditions is closed.	In accordance with the Surveillance Frequency Control Program
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 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~~ ~~and~~ each automatic PCIV, except for MSIVs, is within limits.	In accordance with the Inservice Testing Program

and not locked, sealed, or otherwise secured

and not locked, sealed, or otherwise secured

power operated,

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER until all OPERABLE IRM channels ≤ 25/40 divisions of full scale on Range 7.	12 hours
C. Suppression pool average temperature > 105°F. AND Any OPERABLE IRM channel > 25/40 divisions of full scale on Range 7. AND Performing testing that adds heat to the suppression pool.	C.1 Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > 110°F ~~but ≤ 120°F~~.	D.1 Place the reactor mode switch in the shutdown position.	Immediately
	AND	
	D.2 ~~Verify~~ Determine suppression pool average temperature ~~≤ 120°F~~.	Once per 30 minutes
	AND	
	D.3 Be in MODE 4.	36 hours

(continued)

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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

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ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Suspend CORE ALTERATIONS. AND C.3 Initiate action to suspend OPDRVs.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.1	Verify all secondary containment equipment hatches are closed and sealed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.2	Verify one secondary containment access door in each access opening is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.3	----------NOTE---------- The number of standby gas treatment (SGT) subsystem(s) required for this Surveillance is dependent on the secondary containment configuration, and shall be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. ---------- Verify ~~required SGT subsystem(s) will draw down the~~ can be drawn down secondary containment using required standby gas treatment (SGT) subsystem(s) to ≥ 0.20 inch of vacuum water gauge in ≤ 120 seconds.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.4	----------NOTE---------- The number of SGT subsystem(s) required for this Surveillance is dependent on the secondary containment configuration, and shall be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. ---------- Verify ~~required SGT subsystem(s) can maintain~~ the secondary containment can be maintained ≥ 0.20 inch of vacuum water gauge ~~in the secondary containment~~ for 1 hour using required SGT subsystem(s) at a flow rate ≤ 4000 cfm ~~for each subsystem~~.	In accordance with the Surveillance Frequency Control Program

TSTF-269

3.6 CONTAINMENT SYSTEMS

3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

LCO 3.6.4.2 Each SCIV shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by SCIVs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more penetration flow paths with one SCIV inoperable.	A.1 Isolate the affected penetration flow path by use of at least one closed and deactivated automatic valve, closed manual valve, or blind flange.	8 hours
	AND	
	A.2 ----------~~NOTE~~ NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days

(continued)

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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 required to be closed during accident conditions is closed. not locked, sealed, or otherwise secured and is	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.2.2	Verify the isolation time of each power operated ~~and each~~ automatic SCIV is within limits. ,	In accordance with the Surveillance Frequency Control 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

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3.6 CONTAINMENT SYSTEMS

3.6.4.3 Standby Gas Treatment (SGT) System

LCO 3.6.4.3 The Unit 1 and Unit 2 SGT subsystems required to support LCO 3.6.4.1, "Secondary Containment," shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required Unit 1 SGT subsystem inoperable while: 1. Four SGT subsystems required OPERABLE, and 2. Unit 1 reactor building-to-refueling floor plug not installed.	A.1 Restore required Unit 1 SGT subsystem to OPERABLE status.	30 days from discovery of failure to meet the LCO
B. One required Unit 2 SGT subsystem inoperable. OR One required Unit 1 SGT subsystem inoperable for reasons other than Condition A.	B.1 Restore required SGT subsystem to OPERABLE status.	7 days ~~AND~~ ~~30 days from discovery of failure to meet the LCO~~

(continued)

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ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuits.	1 hour AND Once per 8 hours thereafter
	AND		
	A.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4160 V ESF bus concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore required offsite circuit to OPERABLE status.	72 hours ~~AND~~ ~~17 days from discovery of failure to meet LCO 3.8.1.a, b, or c~~
B. One Unit 1 or the swing DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		

(continued)

No change. Included for information only.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND	
	B.3.1 Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR	
	B.3.2 Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours
	AND	
	B.4 Restore DG to OPERABLE status.	72 hours for a Unit 1 DG with the swing DG not inhibited or maintenance restrictions not met AND 14 days for a Unit 1 DG with the swing DG inhibited from automatically aligning to Unit 2 and maintenance restrictions met AND 72 hours for the swing diesel with maintenance restrictions not met

(continued)

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ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.4 (continued)	AND 14 days for the swing diesel with maintenance restrictions met ~~AND~~ ~~17 days from discovery of failure to meet LCO 3.8.1.a, b, or c~~
C. One required Unit 2 DG inoperable	C.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	C.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	AND	
	C.3.1 Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR	
	C.3.2 Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1 or 2. ~~However, credit~~ may be taken for unplanned events that satisfy this SR. ---------- However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit 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
SR 3.8.1.7	----------NOTES---------- normally 1. This Surveillance shall not normally be performed in MODE 1 or 2, except for the swing DG. For the swing DG, this Surveillance shall not be performed in MODE 1 or 2 using the Unit 1 controls. Credit may be taken for unplanned events that satisfy this SR. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. 2. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ---------- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 65.5 Hz; and b. Within 3 seconds following load rejection, the voltage is ≥ 3740 V and ≤ 4580 V.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.8	----------NOTES---------- normally 1. This Surveillance shall not be performed in MODE 1 or 2, except for the swing DG. For the swing DG, this Surveillance shall not be performed in MODE 1 or 2 using the Unit 1 controls. Credit may be taken for unplanned events that satisfy this SR. 2. 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. 3. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ----------	However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced.
	Verify each DG operating at a power factor ≤ 0.88 does not trip and voltage is maintained ≤ 4800 V during and following a load rejection of ≥ 2775 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------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: 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 ≤ 12 seconds, 2. Energizes auto-connected shutdown loads through automatic load sequence timing devices, 3. Maintains steady state voltage ≥ 3740 V and ≤ 4243 V, 4. Maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. Supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

normally

However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.10	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2. ~~However, credit~~ may be taken for unplanned events that satisfy this SR. ----------	
	Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and: a. In ≤ 12 seconds after auto-start achieves voltage ≥ 3740 V, and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4243 V; b. In ≤ 12 seconds after auto-start achieves frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

normally

However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	----------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 each DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ECCS initiation signal ~~except:~~ . ~~a. Engine overspeed;~~ ~~b. Generator differential current; and~~ ~~c. Low lube oil pressure~~.	In accordance with the Surveillance Frequency Control Program

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normally

However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit

non-critical

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not normally be performed in MODE 1 or 2, unless the other two DGs are OPERABLE. If either of the other two DGs becomes inoperable, this surveillance shall be suspended. Credit may be taken for unplanned events that satisfy this SR. 3. 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. 4. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ----------	However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced.
	Verify each DG operating at a power factor ≤ 0.88 operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 3000 kW; and b. For the remaining hours of the test loaded ≥ 2775 kW and ≤ 2825 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 2565 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. 3. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ---------- Verify each DG starts and achieves, in ≤ 12 seconds, voltage ≥ 3740 V and frequency ≥ 58.8 Hz; and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4243 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.14	----------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 each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program

normally

However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	----------NOTE---------- normally This Surveillance shall not be performed in MODE 1, 2, or 3. ~~However, credit~~ may be taken for unplanned events that satisfy this SR. ---------- However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit Verify with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.16	----------NOTE---------- normally This Surveillance shall not be performed in MODE 1, 2, or 3. ~~However, credit~~ may be taken for unplanned events that satisfy this SR. ---------- However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit Verify interval between each sequenced load block is within ± 10% of design interval for each load sequence timing device.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.17	----------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 ≤ 12 seconds, 2. Energizes auto-connected emergency loads through automatic load sequence timing devices, 3. Achieves steady state voltage ≥ 3740 V and ≤ 4243 V, 4. Achieves 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

normally

However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more (Unit 1 or swing bus) DG DC electrical power distribution subsystems inoperable.	B.1 Restore DG DC electrical power distribution subsystem to OPERABLE status.	12 hours ~~AND~~ ~~16 hours from discovery of failure to meet LCO 3.8.7.a~~
C. One or more (Unit 1 or swing bus) AC electrical power distribution subsystems inoperable.	C.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours ~~AND~~ ~~16 hours from discovery of failure to meet LCO 3.8.7.a~~
D. One Unit 1 station service DC electrical power distribution subsystem inoperable.	D.1 Restore Unit 1 station service DC electrical power distribution subsystem to OPERABLE status.	2 hours ~~AND~~ ~~16 hours from discovery of failure to meet LCO 3.8.7.a~~
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours
F. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	F.1 Enter LCO 3.0.3.	Immediately

5.5 Programs and Manuals (continued)

No change. Included for information only.

5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The systems include the Core Spray, High Pressure Coolant Injection, Residual Heat Removal, Reactor Core Isolation Cooling, and Reactor Water Cleanup. The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. System leak test requirements for each system, to the extent permitted by system design and radiological conditions, at refueling cycle intervals or less.

5.5.3 Post Accident Sampling

(Deleted)

5.5.4 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation, including surveillance tests and setpoint determination, in accordance with the methodology in the ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to 10 times the concentrations stated in 10 CFR 20, Appendix B (to paragraphs 20.1001 - 20.2401), Table 2, Column 2;

(continued)

5.5 Programs and Manuals

TSTF-308

5.5.4 Radioactive Effluent Controls Program (continued)

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

INSERT - TS 5.5.4

e. ~~Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year, in accordance with the methodology and parameters in the ODCM, at least every 31 days;~~

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary as follows:

1) For noble gases, less than or equal to a dose rate of 500 mrem/year to the total body and less than or equal to a dose rate of 3000 mrem/year to the skin, and

2) For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days, less than or equal to a dose rate of 1500 mrem/year to any organ;

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

(continued)

INSERT – TS 5.5.4

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Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days;

ISTS
Adoption #1

5.5 Programs and Manuals (continued)

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track FSAR Section 4.2, cyclic and transient occurrences, to ensure that reactor coolant pressure boundary components are maintained within the design limits.

5.5.6 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports.

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda are as follows:

ASME Boiler and Pressure Vessel Code and Applicable Addenda Terminology for Inservice Testing Activities	Required Frequencies for Performing Inservice Testing Activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Yearly or annually	At least once per 366 days

b. The provisions of SR 3.0.2 are applicable to the frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

5.5.7 Ventilation Filter Testing Program (VFTP)

INSERT - TS 5.5.7 → ~~The VFTP will establish the required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2, Sections C.5.c and C.5.d, or: 1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, 2) following painting, fire or chemical release in any ventilation zone communicating with the system, or 3) after every 720 hours of charcoal adsorber operation.~~

(continued)

INSERT – TS 5.5.7

ISTS
Adoption #1

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2, Sections C.5.c and C.5.d, and in accordance with Regulatory Guide 1.52, Revision 2.

No change. Included for information only.

5.5 Programs and Manuals

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

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

1. Tests and evaluations have determined the impact on the Standby Gas Treatment (SGT) System filters of certain types of painting, buffing and grinding, and welding. The use of water based paints and the performance of metal grinding, buffing, or welding are not detrimental to the charcoal filters of the SGT System, either prior to or during operation. These activities will not require surveillance of the system upon their conclusion. This applies to all types of welding conducted at Plant Hatch, and tracking of the quantity of weld material used is not necessary.

2. For testing purposes, the use of refrigerants equivalent to those specified in ASME N510-1989 is acceptable.

---

a. Demonstrate for each of the ESF systems that an inplace test of the HEPA filters shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, Section C.5.c, and ASME N510-1989, Section 10, at the system flowrate specified below.

ESF Ventilation System	Flowrate (cfm)
SGT System	3000 to 4000
Main Control Room Environmental Control (MCREC) System	2250 to 2750

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, Section C.5.d, and ASME N510-1989, Section 11, at the system flowrate specified below.

ESF Ventilation System	Flowrate (cfm)
SGT System	3000 to 4000
MCREC System	2250 to 2750

(continued)

No change. Included for information only.

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, Section C.6.b, and ASME N510-1989, Section 15 and Appendix B, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of ≤ 30°C and greater than or equal to the relative humidity specified below.

ESF Ventilation System	Penetration (%)	RH (%)
SGT System	2.5	95
MCREC System	2.5	95

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters, the prefilters, and the charcoal adsorbers is less than the value specified below when tested in accordance with ASME N510-1989, Section 8.5.1, at the system flowrate specified below.

ESF Ventilation System	ΔP (inches wg)	Flowrate (cfm)
SGT System	< 6	3000 to 4000
MCREC System	< 6	2250 to 2750

e. (Not used)

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the main condenser offgas treatment system, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks.

(continued)

5.5 Programs and Manuals

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5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

The program shall include:

a. The limits for the concentrations of hydrogen in the main condenser offgas treatment system and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion); and

b. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.9 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has ~~not become contaminated with other products during transit, thus altering the quality of the fuel oil; and~~

INSERT - TS 5.5.9

c. ~~b.~~ Total particulate concentration of the fuel oil is ≤ 10 mg/liter when tested every 92 days ~~utilizing the guidance provided in ASTM D-2276, Method A-2 or A-3~~.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program surveillance frequencies.

(continued)

INSERT – TS 5.5.9

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1. An API gravity or an absolute specific gravity within limits,

2. A flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

3. A water and sediment content within limits;

b. Within 31 days following addition of the new fuel oil to storage tanks, verify that the properties of the new fuel oil, other than those addressed in a., above, are within limits for ASTM 2D fuel oil; and

5.5 Programs and Manuals (continued)

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5.5.10 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate limitations and remedial or compensatory actions may be identified to be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, ~~a~~ safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

When a loss of safety function is caused by inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system..

no concurrent loss of offsite power or no concurrent loss of onsite diesel generator(s),

(continued)

1.0 USE AND APPLICATION

No change. Included for information only.

1.3 Completion Times

PURPOSE

The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.

BACKGROUND

Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).

DESCRIPTION

The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the LCO Applicability.

If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition.

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 <u>not</u> result in separate entry into the Condition unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

However, when a <u>subsequent</u> division, subsystem, component, or variable expressed in the Condition is discovered to be inoperable or not within limits, the Completion Time(s) may be extended. To apply this Completion Time extension, two criteria must first be met. The subsequent inoperability:

(continued)

1.3 Completion Times

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DESCRIPTION (continued)

a. Must exist concurrent with the first inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extension does not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each division, subsystem, component or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase "from discovery . . ." ~~Example 1.3-3 illustrates one use of this type of Completion Time. The 10 day Completion Time specified for Conditions A and B in Example 1.3-3 may not be extended~~.

(continued)

1.3 Completion Times

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EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X subsystem inoperable.	A.1 Restore Function X subsystem to OPERABLE status.	7 days ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
B. One Function Y subsystem inoperable.	B.1 Restore Function Y subsystem to OPERABLE status.	72 hours ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
C. One Function X subsystem inoperable. AND One Function Y subsystem inoperable.	C.1 Restore Function X subsystem to OPERABLE status. OR C.2 Restore Function Y subsystem to OPERABLE status.	72 hours 72 hours

(continued)

1.3 Completion Times

TSTF-439

EXAMPLES

EXAMPLE 1.3-3 (continued)

When one Function X subsystem and one Function Y subsystem are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each subsystem, starting from the time each subsystem was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second subsystem was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected subsystem was declared inoperable (i.e., initial entry into Condition A).

~~The Completion Times of Conditions A and B are modified by a logical connector, with a separate 10 day Completion Time measured from the time it was discovered the LCO was not met. In this example, without the separate Completion Time, it would be possible to al~~ternate between ~~Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. The separate Completion Time modified by the phrase "from discovery of failure to meet the LCO" is designed to prevent indefinite continued operation while not meeting the LCO. This Completion Time allows for an exception to the normal "time zero" for beginning the Completion Time "clock." In this instance, the Completion Time "time zero" is specified as commencing at the time the LCO was initially not met, instead of at the time the associated Condition was entered.~~

INSERT - TS 1.3
Example

(continued)

Insert – TS 1.3 Example

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It is possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. However, doing so would be inconsistent with the basis of the Completion Times. Therefore, there shall be administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls shall ensure that the Completion Times for those Conditions are not inappropriately extended.

1.0 USE AND APPLICATION

1.4 Frequency

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PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated Limiting Conditions for Operation (LCO). An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR, as well as certain Notes in the Surveillance column that modify performance requirements.

Sometimes special situations dictate when the requirements of a Surveillance are to be met. They are "otherwise stated" conditions allowed by SR 3.0.1. They may be stated as clarifying Notes in the Surveillance, as part of the Surveillance, or both. ~~Example 1.4-4 discusses these special situations.~~

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

The use of "met" or "performed" in these instances conveys specific meanings. A Surveillance is "met" only when the acceptance criteria are satisfied. Known failure of the requirements of a Surveillance, even without a Surveillance specifically being "performed," constitutes a Surveillance not "met." "Performance" refers only to the requirement to specifically determine the ability to meet the acceptance criteria.

INSERT - TS 1.4 Description → ~~SR 3.0.4 restrictions would not apply if both the following conditions are satisfied:~~

(continued)

Insert – TS 1.4 Description

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Some Surveillances contain notes that modify the Frequency of performance or the conditions during which the acceptance criteria must be satisfied. For these Surveillances, the MODE-entry restrictions of SR 3.0.4 may not apply. Such a Surveillance is not required to be performed prior to entering a MODE or other specified condition in the Applicability of the associated LCO if any of the following three conditions are satisfied:

a. The Surveillance is not required to be met in the MODE or other specified condition to be entered; or

b. The Surveillance is required to be met in the MODE or other specified condition to be entered, but has been performed within the specified Frequency (i.e., it is current) and is known not to be failed; or

c. The Surveillance is required to be met, but not performed, in the MODE or other specified condition to be entered, and is known not to be failed.

Examples 1.4-3, 1.4-4, 1.4-5, and 1.4-6 discusses these special situations.

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1.4 Frequency

DESCRIPTION (continued)

~~a. The Surveillance is not required to be performed; and~~

~~b. The Surveillance is not required to be met or, even if required to be met, is not known to be failed.~~

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the interval specified in the Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Examples 1.4-3 and 1.4-4), then SR 3.0.3 becomes applicable.

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, then SR 3.0.4 becomes applicable. The surveillance must be performed within the Frequency requirements of SR 3.0.2, as modified by SR 3.0.3, prior to entry into the mode or other specified condition or the LCO is considered not met (in accordance with SR 3.0.1) and LCO 3.0.4 becomes applicable.

(continued)

1.4 Frequency

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EXAMPLES (continued)

EXAMPLE 1.4-4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Only required to be met in MODE 1. ----------	
Verify leakage rates are within limits.	24 hours

Example 1.4-4 specifies that the requirements of this Surveillance do not have to be met until the unit is in MODE 1. The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour (plus the extension allowed by SR 3.0.2) interval, but the unit was not in MODE 1, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES, even with the 24 hour Frequency exceeded, provided the MODE change was not made into MODE 1. Prior to entering MODE 1 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

INSERT - TS 1.4 Example 1.4-5

INSERT - TS 1.4 Example 1.4-6

Insert – TS 1.4 Example 1.4-5

EXAMPLE 1.4-5

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Only required to be performed in MODE 1. ----------	
Perform complete cycle of the valve.	7 days

The interval continues, whether or not the unit operation is in MODE 1, 2, or 3 (the assumed Applicability of the associated LCO) between performances.

As the Note modifies the required performance of the Surveillance, the Note is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is not in MODE 1, this Note allows entry into and operation in MODES 2 and 3 to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency" if completed prior to entering MODE 1. Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was not in MODE 1, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not result in entry into MODE 1.

Once the unit reaches MODE 1, the requirement for the Surveillance to be performed within its specified Frequency applies and would require that the Surveillance had been performed. If the Surveillance were not performed prior to entering MODE 1, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

Insert – TS 1.4 Example 1.4-6

EXAMPLE 1.4-6

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Not required to be met in MODE 3. ----------	
Verify parameter is within limits.	24 hours

Example 1.4-6 specifies that the requirements of this Surveillance do not have to be met while the unit is in MODE 3 (the assumed Applicability of the associated LCO is MODES 1, 2, and 3). The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However. the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), and the unit was in MODE 3, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES to enter MODE 3, even with the 24 hour Frequency exceeded, provided the MODE change does not result in entry into MODE 2. Prior to entering MODE 2 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

SURVEILLANCE REQUIREMENTS

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----------NOTE----------
During single control rod scram time Surveillances, the control rod drive (CRD) pumps shall be isolated from the associated scram accumulator.

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify each 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 reactor pressure vessel~~ ~~AND~~ Prior to exceeding 40% RTP after each reactor shutdown ≥ 120 days
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 exceeding 40% RTP after fuel movement within the affected fuel cell AND	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 work on control rod or CRD System that could affect scram time

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3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Sodium pentaborate solution not within Region A limits of Figure 3.1.7-1 or 3.1.7-2, but within the Region B limits.	A.1 Restore sodium pentaborate solution to within Region A limits.	72 hours ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
B. One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	7 days ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1 Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	12 hours

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.2	----------NOTE---------- Not required to be performed until 12 hours after THERMAL POWER ≥ 24% RTP. ---------- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 24% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.3	(Not used.)	
SR 3.3.1.1.4	----------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 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.6 (Not used.)	~~Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.~~	~~Prior to withdrawing SRMs from the fully inserted position~~

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.7 (Not used.)	~~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 3.3.1.1.8	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	----------NOTE---------- 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 FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.11	Verify Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 27.6% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

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Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitor					
a. Neutron Flux - High	2	2[d]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 ~~SR 3.3.1.1.6~~ ~~SR 3.3.1.1.7~~ SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
	5[a]	2[d]	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
b. Inop	2	2[d]	G	SR 3.3.1.1.4 SR 3.3.1.1.15	NA
	5[a]	2[d]	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
2. Average Power Range Monitor					
a. Neutron Flux - High (Setdown)	2	3[c]	G	SR 3.3.1.1.1 ~~SR 3.3.1.1.7~~ SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 20% RTP
b. Simulated Thermal Power - High	1	3[c]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 0.57W + 56.8% RTP and ≤ 115.5% RTP[b]
c. Neutron Flux - High	1	3[c]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 120% RTP
d. Inop	1, 2	3[c]	G	SR 3.3.1.1.10	NA

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) 0.57W + 56.8% - 0.57 ΔW RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) Each APRM channel provides inputs to both trip systems.

(d) One channel in each quadrant of the core must be OPERABLE whenever the IRMs are required to be OPERABLE. Both the RWM and a second licensed operator must verify compliance with the withdrawal sequence when less than three channels in any trip system are OPERABLE.

No change. Included for information only.

3.3 INSTRUMENTATION

3.3.2.1 Control Rod Block Instrumentation

LCO 3.3.2.1 The control rod block instrumentation for each Function in Table 3.3.2.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2.1-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One rod block monitor (RBM) channel inoperable.	A.1 Restore RBM channel to OPERABLE status.	24 hours
B. Required Action and associated Completion Time of Condition A not met. OR Two RBM channels inoperable.	B.1 Place one RBM channel in trip.	1 hour
C. Rod worth minimizer (RWM) inoperable during reactor startup.	C.1 Suspend control rod movement except by scram. OR C.2.1.1 Verify ≥ 12 rods withdrawn. OR	Immediately Immediately

(continued)

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ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.1.2 Verify by administrative methods that startup with RWM inoperable has not been performed in the last ~~calendar year~~ 12 months.	Immediately
	AND	
	C.2.2 Verify movement of control rods is in compliance with banked position withdrawal sequence (BPWS) by a second licensed operator or other qualified member of the technical staff.	During control rod movement
D. RWM inoperable during reactor shutdown.	D.1 Verify movement of control rods is in compliance with BPWS by a second licensed operator or other qualified member of the technical staff.	During control rod movement
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

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Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1
1.	Reactor Steam Dome Pressure	2	E
2.	Reactor Vessel Water Level		
	a. -317 inches to -17 inches	2	E
	b. -150 inches to +60 inches	2	E
	c. 0 inches to +60 inches	2	E
	d. 0 inches to +400 inches	1	NA
3.	Suppression Pool Water Level		
	a. 0 inches to 300 inches	2	E
	b. 133 inches to 163 inches	2	E
4.	Drywell Pressure		
	a. -10 psig to +90 psig	2	E
	b. -5 psig to +5 psig	2	E
	c. 0 psig to +250 psig	2	E
5.	Drywell Area Radiation (High Range)	2	F
6.	Primary Containment Isolation Valve Position Penetration Flow Path	2 per penetration flow path[a][b]	E
7.	(Deleted)		
8.	(Deleted)		
9.	Suppression Pool Water Temperature	2[c]	E
10.	Drywell Temperature in Vicinity of Reactor Level Instrument Reference Leg	6	E
11.	Diesel Generator (DG) Parameters		
	a. Output Voltage	1 per DG	NA
	b. Output Current	1 per DG	NA
	c. Output Power	1 per DG	NA
	d. Battery Voltage	1 per DG	NA
12.	RHR Service Water Flow	2	E

(a) Not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Monitoring each of four quadrants.

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3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

LCO 3.3.6.1 The primary containment isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

1. Penetration flow paths may be unisolated intermittently under administrative controls.

~~NOTE~~

2. Separate Condition entry is allowed for each channel.

NOTES

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	12 hours for Functions 2.a, 2.b, ~~and~~ 6.b, 7.a, and 7.b AND 24 hours for Functions other than Functions 2.a, 2.b, ~~and~~ 6.b, 7.a, and 7.b
B. ----------NOTE---------- Not applicable for Function 5.c. ---------- One or more automatic Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	D.1 Isolate associated main steam line (MSL). OR D.2.1 Be in MODE 3. AND D.2.2 Be in MODE 4.	12 hours 12 hours 36 hours
E. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	E.1 Be in MODE 2.	6 hours
F. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	F.1 Isolate the affected penetration flow path(s).	1 hour
H. ~~G.~~ As required by Required Action C.1 and referenced in Table 3.3.6.1-1. OR Required Action and associated Completion Time of Condition F or G not met.	H.1 ~~G.1~~ Be in MODE 3. AND H.2 ~~G.2~~ Be in MODE 4.	12 hours 36 hours
I. ~~H.~~ As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	I.1 ~~H.1~~ Declare Standby Liquid Control (SLC) System inoperable. OR I.2 ~~H.2~~ Isolate the Reactor Water Cleanup (RWCU) System.	1 hour 1 hour

INSERT - TS 3.3.6.1 Condition G

(continued)

INSERT - TS 3.3.6.1 Condition G

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G.	As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	G.1	Isolate the affected penetration flow path(s).	24 hours

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~I.~~ J. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	~~I.1~~ J.1 Initiate action to restore channel to OPERABLE status.	Immediately
	OR	
	~~I.2~~ J.2 Initiate action to isolate the Residual Heat Removal (RHR) Shutdown Cooling System.	Immediately

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

(continued)

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Table 3.3.6.1-1 (page 1 of 4)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level - Low Low Low, Level 1	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ -113 inches
b. Main Steam Line Pressure - Low	1	2	E	SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 825 psig
c. Main Steam Line Flow - High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 138% rated steam flow
d. Condenser Vacuum - Low	1, 2[a], 3[a]	2	D	SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 7 inches Hg vacuum
e. Main Steam Tunnel Temperature - High	1,2,3	6	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 194°F
f. Turbine Building Area Temperature - High	1,2,3	16[b]	D	SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 200°F
2. Primary Containment Isolation					
a. Reactor Vessel Water Level - Low, Level 3	1,2,3	2	~~G~~ H	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches
b. Drywell Pressure - High	1,2,3	2	~~G~~ H	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig

(continued)

(a) With any turbine stop valve not closed.

(b) With 8 channels per trip string. Each trip string shall have 2 channels per main steam line, with no more than 40 ft separating any two OPERABLE channels.

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Table 3.3.6.1-1 (page 2 of 4)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Primary Containment Isolation (continued)					
c. Drywell Radiation - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 138 R/hr
d. Reactor Building Exhaust Radiation - High	1,2,3	2	H → ~~G~~	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.6	≤ 80 mR/hr
e. Refueling Floor Exhaust Radiation - High	1,2,3	2	H → ~~G~~	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.6	≤ 80 mR/hr
3. High Pressure Coolant Injection (HPCI) System Isolation					
a. HPCI Steam Line Flow - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 303% rated steam flow
b. HPCI Steam Supply Line Pressure - Low	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 100 psig
c. HPCI Turbine Exhaust Diaphragm Pressure - High	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 20 psig
d. Drywell Pressure - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig
e. HPCI Pipe Penetration Room Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
f. Suppression Pool Area Ambient Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F

(continued)

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Table 3.3.6.1-1 (page 4 of 4)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. RCIC System Isolation (continued)					
g. RCIC Suppression Pool Area Differential Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 42°F
h. Emergency Area Cooler Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
5. RWCU System Isolation					
a. Area Temperature - High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 150°F
b. Area Ventilation Differential Temperature - High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 67°F
c. SLC System Initiation	1,2	1(c)	~~H~~ I	SR 3.3.6.1.6	NA
d. Reactor Vessel Water Level - Low Low, Level 2	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ - 47 inches
6. RHR Shutdown Cooling System Isolation					
a. Reactor Steam Dome Pressure - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 145 psig
b. Reactor Vessel Water Level - Low, Level 3	3,4,5	2(d)	~~I~~ J	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches

INSERT - TS Table 3.3.6.1-1

(c) SLC System Initiation only inputs into one of the two trip systems.

(d) Only one trip system required in MODES 4 and 5 when RHR Shutdown Cooling System integrity maintained.

INSERT – TS Table 3.3.6.1-1

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7. Traversing Incore Probe System Isolation					
a. Reactor Vessel Water Level - Low, Level 3	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches
b. Drywell Pressure - High	1, 2, 3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig

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3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.1 ECCS - Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of six of seven safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except high pressure coolant injection (HPCI) and ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig.

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to HPCI.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.	7 days
INSERT - TS 3.5.1 Condition A		
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours
C. HPCI System inoperable.	C.1 Verify by administrative means RCIC System is OPERABLE. AND C.2 Restore HPCI System to OPERABLE status.	1 hour 14 days

(continued)

INSERT – TS 3.5.1 Condition A

OR

One LPCI pump in both LPCI susbsystems inoperable.

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. HPCI System inoperable. AND ~~One low pressure ECCS injection/spray subsystem inoperable.~~ Condition A entered.	D.1 Restore HPCI System to OPERABLE status. OR D.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours 72 hours
E. Two or more ADS valves inoperable. OR Required Action and associated Completion Time of Condition C or D not met.	E.1 Be in MODE 3. AND E.2 Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours
F. Two or more low pressure ECCS injection/spray subsystems inoperable. for reasons other than Condition A OR HPCI System and two or more ADS valves inoperable.	F.1 Enter LCO 3.0.3.	Immediately

No change. Included for information only.

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV, except reactor building-to-suppression chamber vacuum breakers, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation."

ACTIONS

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

1. Penetration flow paths except for 18 inch purge valve penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----------NOTE---------- Only applicable to penetration flow paths with two PCIVs. ---------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. AND	4 hours except for main steam line AND 8 hours for main steam line (continued)

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NOTES

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued) 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means.	A.2 ----------NOTE---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside primary containment AND 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, for isolation devices inside primary containment
B. ----------NOTE---------- Only applicable to penetration flow paths with two PCIVs. ---------- One or more penetration flow paths with two PCIVs inoperable except due to leakage not within limit.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour

(continued)

and penetrations with a closed system

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ----------NOTE---------- Only applicable to penetration flow paths with only one PCIV. ---------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limits.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	4 hours except for excess flow check valve (EFCV) line AND ~~12 hours for EFCV line~~ 72 hours for EFCV line and penetrations with a closed system
	AND	
	C.2 ----------~~NOTE~~ NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days
D. One or more penetration flow paths with leakage not within limit.	D.1 Restore leakage to within limit.	4 hours
E. Required Action and associated Completion Time of Condition A, B, C, or D not met in MODE 1, 2, or 3.	E.1 Be in MODE 3.	12 hours
	AND	
	E.2 Be in MODE 4.	36 hours

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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 is required to be closed during accident conditions is closed.	In accordance with the Surveillance Frequency Control Program
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 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~~ ~~and~~ each automatic PCIV, except for MSIVs, is within limits.	In accordance with the Inservice Testing Program

and not locked, sealed, or otherwise secured

and not locked, sealed, or otherwise secured

power operated,

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER until all OPERABLE IRM channels ≤ 25/40 divisions of full scale on Range 7.	12 hours
C. Suppression pool average temperature > 105°F. AND Any OPERABLE IRM channel > 25/40 divisions of full scale on Range 7. AND Performing testing that adds heat to the suppression pool.	C.1 Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > 110°F ~~but ≤ 120°F~~.	D.1 Place the reactor mode switch in the shutdown position.	Immediately
	AND	
	D.2 ~~Verify~~ Determine suppression pool average temperature ~~≤ 120°F~~.	Once per 30 minutes
	AND	
	D.3 Be in MODE 4.	36 hours

(continued)

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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

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ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Suspend CORE ALTERATIONS. AND C.3 Initiate action to suspend OPDRVs.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.1	Verify all secondary containment equipment hatches are closed and sealed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.2	Verify one secondary containment access door in each access opening is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.3	----------NOTE---------- The number of standby gas treatment (SGT) subsystem(s) required for this Surveillance is dependent on the secondary containment configuration, and shall be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. ---------- Verify ~~required SGT subsystem(s) will draw down the~~ can be drawn down secondary containment to ≥ 0.20 inch of vacuum water gauge in ≤ 120 seconds using required standby gas treatment (SGT) subsystem(s).	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.4	----------NOTE---------- The number of SGT subsystem(s) required for this Surveillance is dependent on the secondary containment configuration, and shall be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. ---------- Verify ~~required SGT subsystem(s) can maintain~~ the secondary containment can be maintained ≥ 0.20 inch of vacuum water gauge ~~in the secondary containment~~ for 1 hour using required SGT subsystem(s) at a flow rate ≤ 4000 cfm ~~for each subsystem~~.	In accordance with the Surveillance Frequency Control Program

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3.6 CONTAINMENT SYSTEMS

3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

LCO 3.6.4.2 Each SCIV shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRV).

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by SCIVs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more penetration flow paths with one SCIV inoperable.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	8 hours
	AND	
	A.2 ----------~~NOTE~~---------- NOTES 1. Isolation devices in high radiation areas may be verified by use of administrative means. ----------	
2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means.	Verify the affected penetration flow path is isolated.	Once per 31 days

(continued)

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SURVEILLANCE REQUIREMENTS

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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 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 ~~and each~~ automatic SCIV is within limits.	In accordance with the Surveillance Frequency Control 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

not locked, sealed, or otherwise secured and is

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required Unit 2 SGT subsystem inoperable. OR One required Unit 1 SGT subsystem inoperable for reasons other than Condition A.	B.1 Restore required SGT subsystem to OPERABLE status.	7 days ~~AND~~ ~~30 days from discovery of failure to meet the LCO~~
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. Required Action and associated Completion Time of Condition A or B not met during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	----------NOTE---------- LCO 3.0.3 is not applicable. ---------- D.1 Place remaining OPERABLE SGT subsystem(s) in operation. OR D.2.1 Suspend movement of irradiated fuel assemblies in secondary containment. AND D.2.2 Suspend CORE ALTERATIONS. AND D.2.3 Initiate action to suspend OPDRVs.	 Immediately Immediately Immediately Immediately

(continued)

ACTIONS

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---NOTE---
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuits.	1 hour AND Once per 8 hours thereafter
	AND		
	A.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4160 V ESF bus concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore required offsite circuit to OPERABLE status.	72 hours ~~AND~~ ~~17 days from discovery of failure to meet LCO 3.8.1.a, b, or c~~
B. One Unit 2 or the swing DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		

(continued)

No change. Included for information only.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND	
	B.3.1 Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR	
	B.3.2 Perform SR 3.8.1.2.a for OPERABLE DG(s)	24 hours
	AND	
	B.4 Restore DG to OPERABLE status.	72 hours for a Unit 2 DG with the swing DG not inhibited or maintenance restrictions not met AND 14 days for a Unit 2 DG with the swing DG inhibited from automatically aligning to Unit 1 and maintenance restrictions met AND 72 hours for the swing diesel with maintenance restrictions not met

(continued)

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ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.4 (continued)	AND 14 days for the swing diesel with maintenance restrictions met ~~AND~~ ~~17 days from discovery of failure to meet LCO 3.8.1.a, b, or c~~
C. One required Unit 1 DG inoperable.	C.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	C.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	AND	
	C.3.1 Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR	
	C.3.2 Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	----------NOTE---------- This Surveillance shall not be performed in MODE 1 or 2. ~~However, credit~~ normally may be taken for unplanned events that satisfy this SR. ---------- However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit 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
SR 3.8.1.7	----------NOTES---------- normally 1. This Surveillance shall not be performed in MODE 1 or 2, except for the swing DG. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. For the swing DG, this Surveillance shall not be performed in MODE 1 or 2 using the Unit 2 controls. Credit may be taken for unplanned events that satisfy this SR. 2. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ---------- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 65.5 Hz; and b. Within 3 seconds following load rejection, the voltage is ≥ 3740 V and ≤ 4580 V.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.8	----------NOTES---------- 1. This Surveillance shall not normally be performed in MODE 1 or 2, except for the swing DG. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. For the swing DG, this Surveillance shall not be performed in MODE 1 or 2 using the Unit 2 controls. Credit may be taken for unplanned events that satisfy this SR. 2. 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. 3. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ----------	
	Verify each DG operating at a power factor ≤ 0.88 does not trip and voltage is maintained ≤ 4800 V during and following a load rejection of ≥ 2775 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------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. ---------- However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit normally Verify on an actual or simulated loss of offsite power 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 ≤ 12 seconds, 2. Energizes auto-connected shutdown loads through automatic load sequence timing devices, 3. Maintains steady state voltage ≥ 3740 V and ≤ 4243 V, 4. Maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. Supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.10	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2. ~~However, credit~~ may be taken for unplanned events that satisfy this SR. normally However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit ---------- Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and: a. In ≤ 12 seconds after auto-start achieves voltage ≥ 3740 V, and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4243 V; b. In ≤ 12 seconds after auto-start achieves frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY TSTF-400
SR 3.8.1.11	----------NOTE---------- normally This Surveillance shall not be performed in MODE 1, 2, or 3. ~~However, credit~~ may be taken for unplanned events that satisfy this SR. ---------- non-critical Verify each DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ECCS initiation signal ~~except:~~ . ~~a. Engine overspeed;~~ ~~b. Generator differential current; and~~ ~~c. Low lube oil pressure.~~	In accordance with the Surveillance Frequency Control Program

However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not normally be performed in MODE 1 or 2, unless the other two DGs are OPERABLE. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. If either of the other two DGs becomes inoperable, this Surveillance shall be suspended. Credit may be taken for unplanned events that satisfy this SR. 3. 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. 4. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ----------	
	Verify each DG operating at a power factor ≤ 0.88 operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 3000 kW; and b. For the remaining hours of the test loaded ≥ 2775 kW and ≤ 2825 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 2565 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. 3. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ---------- Verify each DG starts and achieves, in ≤ 12 seconds, voltage ≥ 3740 V and frequency ≥ 58.8 Hz; and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4243 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.14	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. ~~However, credit~~ may be taken for unplanned events that satisfy this SR. ---------- However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. ~~However, credit~~ may be taken for unplanned events that satisfy this SR. ---------- However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit Verify with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.16	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. ~~However, credit~~ may be taken for unplanned events that satisfy this SR. ---------- However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit Verify interval between each sequenced load block is within ± 10% of design interval for each load sequence timing device.	In accordance with the Surveillance Frequency Control Program

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.17	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall ~~not~~ normally 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 ≤ 12 seconds, 2. Energizes auto-connected emergency loads through automatic load sequence timing devices, 3. Achieves steady state voltage ≥ 3740 V and ≤ 4243 V, 4. Achieves 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

However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more (Unit 2 or swing bus) DG DC electrical power distribution subsystems inoperable.	B.1 Restore DG DC electrical power distribution subsystem to OPERABLE status.	12 hours ~~AND~~ ~~16 hours from discovery of failure to meet LCO 3.8.7.a~~
C. One or more (Unit 2 or swing bus) AC electrical power distribution subsystems inoperable.	C.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours ~~AND~~ ~~16 hours from discovery of failure to meet LCO 3.8.7.a~~
D. One Unit 2 station service DC electrical power distribution subsystem inoperable.	D.1 Restore Unit 2 station service DC electrical power distribution subsystem to OPERABLE status.	2 hours ~~AND~~ ~~16 hours from discovery of failure to meet LCO 3.8.7.a~~
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	12 hours 36 hours
F. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	F.1 Enter LCO 3.0.3.	Immediately

5.5 Programs and Manuals (continued)

No change. Included for information only.

5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The systems include the Core Spray, High Pressure Coolant Injection, Residual Heat Removal, Reactor Core Isolation Cooling, and Reactor Water Cleanup. The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. System leak test requirements for each system, to the extent permitted by system design and radiological conditions, at refueling cycle intervals or less.

5.5.3 Post Accident Sampling

(Deleted)

5.5.4 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation, including surveillance tests and setpoint determination, in accordance with the methodology in the ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to 10 times the concentrations stated in 10 CFR 20, Appendix B (to paragraphs 20.1001 - 20.2401), Table 2, Column 2;

(continued)

5.5 Programs and Manuals

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5.5.4 Radioactive Effluent Controls Program (continued)

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

INSERT - TS 5.5.4

e. ~~Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year, in accordance with the methodology and parameters in the ODCM, at least every 31 days;~~

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary as follows:

1) For noble gases, less than or equal to a dose rate of 500 mrem/year to the total body and less than or equal to a dose rate of 3000 mrem/year to the skin, and

2) For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days, less than or equal to a dose rate of 1500 mrem/year to any organ;

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

(continued)

INSERT – TS 5.5.4

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Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days;

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track FSAR Section 5.2, cyclic and transient occurrences, to ensure that reactor coolant pressure boundary components are maintained within the design limits.

5.5.6 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports.

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda are as follows:

ASME Boiler and Pressure Vessel Code and Applicable Addenda Terminology for Inservice Testing Activities	Required Frequencies for Performing Inservice Testing Activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Yearly or annually	At least once per 366 days

b. The provisions of SR 3.0.2 are applicable to the frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

5.5.7 Ventilation Filter Testing Program (VFTP)

INSERT - TS 5.5.7 →

~~The VFTP will establish the required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2, Sections C.5.c and C.5.d, or: 1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, 2) following painting, fire or chemical release in any ventilation zone communicating with the system, or 3) after every 720 hours of charcoal adsorber operation.~~

(continued)

INSERT – TS 5.5.7

ISTS
Adoption #1

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2, Sections C.5.c and C.5.d, and in accordance with Regulatory Guide 1.52, Revision 2.

5.5 Programs and Manuals

No change. Included for information only.

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

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

1. Tests and evaluations have determined the impact on the Standby Gas Treatment (SGT) System filters of certain types of painting, buffing and grinding, and welding. The use of water based paints and the performance of metal grinding, buffing, or welding are not detrimental to the charcoal filters of the SGT System, either prior to or during operation. These activities will not require surveillance of the system upon their conclusion. This applies to all types of welding conducted at Plant Hatch, and tracking of the quantity of weld material used is not necessary.

2. For testing purposes, the use of refrigerants equivalent to those specified in ASME N510-1989 is acceptable.

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a. Demonstrate for each of the ESF systems that an inplace test of the HEPA filters shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, Section C.5.c, and ASME N510-1989, Section 10, at the system flowrate specified below.

ESF Ventilation System	Flowrate (cfm)
SGT System	3000 to 4000
Main Control Room Environmental Control (MCREC) System	2250 to 2750

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass < 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, Section C.5.d, and ASME N510-1989, Section 11, at the system flowrate specified below.

ESF Ventilation System	Flowrate (cfm)
SGT System	3000 to 4000
MCREC System	2250 to 2750

(continued)

5.5 Programs and Manuals

No change. Included for information only.

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, Section C.6.b, and ASME N510-1989, Section 15 and Appendix B, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of ≤ 30°C and greater than or equal to the relative humidity specified below.

ESF Ventilation System	Penetration (%)	RH (%)
SGT System	2.5	95
MCREC System	2.5	95

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters, the prefilters, and the charcoal adsorbers is less than the value specified below when tested in accordance with ASME N510-1989, Section 8.5.1, at the system flowrate specified below.

ESF Ventilation System	ΔP (inches wg)	Flowrate (cfm)
SGT System	< 6	3000 to 4000
MCREC System	< 6	2250 to 2750

e. (Not used)

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the main condenser offgas treatment system, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks.

(continued)

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5.5 Programs and Manuals

5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

The program shall include:

a. The limits for the concentrations of hydrogen in the main condenser offgas treatment system and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion); and

b. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.9 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has ~~not become contaminated with other products during transit, thus altering the quality of the fuel oil; and~~

INSERT - TS 5.5.9

~~b.~~ c. Total particulate concentration of the fuel oil is ≤ 10 mg/liter when tested every 92 days ~~utilizing the guidance provided in ASTM D-2276, Method A-2 or A-3~~.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program surveillance frequencies.

(continued)

INSERT – TS 5.5.9

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1. An API gravity or an absolute specific gravity within limits,

2. A flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

3. A water and sediment content within limits;

b. Within 31 days following addition of the new fuel oil to storage tanks, verify that the properties of the new fuel oil, other than those addressed in a., above, are within limits for ASTM 2D fuel oil; and

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5.5 Programs and Manuals (continued)

5.5.10 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate limitations and remedial or compensatory actions may be identified to be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, ~~a~~ safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

no concurrent loss of offsite power or no concurrent loss of onsite diesel generator(s),

When a loss of safety function is caused by inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

(continued)

Edwin I. Hatch Nuclear Plant
Request for Technical Specifications Amendment
Adoption of Generic Technical Specification Changes

Enclosure 3

Example Marked-Up Technical Specifications Bases Pages

Index of Affected Technical Specification Bases Pages vs. Traveler or Change

Unit 1 Bases

Page	Traveler or Change
B3.0-9	TSTF-273-A
B3.1-22	TSTF-222-A
B3.1-23	TSTF-222-A
B3.1-37	TSTF-439-A
B3.1-38	TSTF-439-A
B3.3-24	TSTF-264-A
B3.3-25	TSTF-264-A
B3.3-26	TSTF-264-A
B3.3-33	TSTF-264-A
B3.3-35	TSTF-264-A
B3.3-63	TSTF-295-A
B3.3-64	TSTF-295-A
B3.3-138	TSTF-306-A
B3.3-153	TSTF-306-A
B3.3-156	TSTF-306-A
B3.3-157	TSTF-306-A
B3.5-5	TSTF-318-A
B3.5-7	TSTF-318-A
B3.6-18	TSTF-269-A
B3.6-20	TSTF-30-A, TSTF-269-A, TSTF-323-A
B3.6-22	TSTF-45-A
B3.6-23	TSTF-45-A, TSTF-46-A
B3.6-26	TSTF-30-A
B3.6-50	TSTF-458-T
B3.6-79	TSTF-322-A
B3.6-80	TSTF-322-A
B3.6-82	TSTF-46-A
B3.6-84	TSTF-269-A
B3.6-85	TSTF-45-A
B3.6-86	TSTF-46-A
B3.8-7	TSTF-439-A
B3.8-8	TSTF-439-A
B3.8-11	TSTF-439-A
B3.8-24	TSTF-283-A
B3.8-25	TSTF-283-A
B3.8-26	TSTF-283-A
B3.8-28	TSTF-283-A
B3.8-29	TSTF-283-A, TSTF-400-A
B3.8-30	TSTF-283-A
B3.8-31	TSTF-283-A
B3.8-32	TSTF-283-A
B3.8-33	TSTF-283-A
B3.8-34	TSTF-283-A
B3.8-35	TSTF-283-A
B3.8-77	TSTF-439-A
B3.8-78	TSTF-439-A
B3.8-79	TSTF-439-A
B3.8-80	TSTF-439-A

Unit 2 Bases

Page	Traveler or Change
B3.0-9	TSTF-273-A
B3.1-22	TSTF-222-A
B3.1-23	TSTF-222-A
B3.1-24	TSTF-222-A
B3.1-37	TSTF-439-A
B3.1-38	TSTF-439-A
B3.3-24	TSTF-264-A
B3.3-25	TSTF-264-A
B3.3-26	TSTF-264-A
B3.3-33	TSTF-264-A
B3.3-35	TSTF-264-A
B3.3-63	TSTF-295-A
B3.3-64	TSTF-295-A
B3.3-138	TSTF-306-A
B3.3-153	TSTF-306-A
B3.3-156	TSTF-306-A
B3.3-157	TSTF-306-A
B3.5-5	TSTF-318-A
B3.5-7	TSTF-318-A
B3.6-18	TSTF-269-A
B3.6-20	TSTF-30-A, TSTF-269-A, TSTF-323-A
B3.6-22	TSTF-45-A
B3.6-23	TSTF-45-A, TSTF-46-A
B3.6-27	TSTF-30-A

Unit 2 Bases(cont'd)

Page	Traveler or Change
B3.6-51	TSTF-458-T
B3.6-80	TSTF-322-A
B3.6-81	TSTF-322-A
B3.6-83	TSTF-46-A
B3.6-85	TSTF-269-A
B3.6-86	TSTF-45-A
B3.6-87	TSTF-46-A
B3.8-7	TSTF-439-A
B3.8-8	TSTF-439-A
B3.8-11	TSTF-439-A
B3.8-24	TSTF-283-A
B3.8-25	TSTF-283-A
B3.8-26	TSTF-283-A
B3.8-28	TSTF-283-A
B3.8-29	TSTF-283-A, TSTF-400-A
B3.8-30	TSTF-283-A
B3.8-31	TSTF-283-A
B3.8-32	TSTF-283-A
B3.8-33	TSTF-283-A
B3.8-34	TSTF-283-A
B3.8-35	TSTF-283-A
B3.8-77	TSTF-439-A
B3.8-78	TSTF-439-A
B3.8-79	TSTF-439-A
B3.8-80	TSTF-439-A

No change. Included for information only.

BASES

LCO 3.0.5 (continued)

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the SRs.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of an SR on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of an SR on another channel in the same trip system.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs

(continued)

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BASES

LCO 3.0.6 (continued)

entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.10, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon failure to meet two or more LCOs concurrently, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross division checks to identify a loss of safety function for those support systems that support safety systems are required. The cross division check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

INSERT - LCO 3.0.6 Bases

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Special Operations LCOs in Section 3.10 allow specified TS requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Special Operations LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Special Operations LCOs is optional. A special operation may be performed either under the provisions of the appropriate Special Operations LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Special Operations LCO, the requirements of the

(continued)

INSERT – LCO 3.0.6 Bases

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operation is being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restriction for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

When a loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately addresses the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

No change. Included for information only.

BASES

LCO (continued)

This LCO applies only to OPERABLE control rods since inoperable control rods will be inserted and disarmed (LCO 3.1.3). Slow scramming control rods may be conservatively declared inoperable and not accounted for as "slow" control rods.

APPLICABILITY

In MODES 1 and 2, a scram is assumed to function during transients and accidents analyzed for these plant conditions. These events are assumed to occur during startup and power operation; therefore, the scram function of the control rods is required during these MODES. In MODES 3 and 4, with the mode switch in shutdown, control rod block prevents withdrawal of control rods. This provides adequate requirements for control rod scram capability during these conditions. Scram requirements in MODE 5 are contained in LCO 3.9.5, "Control Rod OPERABILITY - Refueling."

ACTIONS

A.1

When the requirements of this LCO are not met, the rate of negative reactivity insertion during a scram may not be within the assumptions of the safety analysis. Therefore, 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. 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

The four SRs of this LCO are modified by a Note stating that during a single control rod scram time Surveillance, the CRD pumps shall be isolated from the associated scram accumulator. With the CRD pump isolated, (i.e., charging valve closed) the influence of the CRD pump head does not affect the single control rod scram times. During a full core scram, the CRD pump head would be seen by all control rods and would have a negligible effect on the scram insertion times.

SR 3.1.4.1

The scram reactivity used in DBA and transient analyses is based on an assumed control rod scram time. Measurement of the scram times with reactor steam dome pressure ≥ 800 psig demonstrates

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1 (continued)

acceptable scram times for the transients analyzed in References 3 and 4.

Maximum scram insertion times occur at a reactor steam dome pressure of approximately 800 psig because of the competing effects of reactor steam dome pressure and stored accumulator energy. Therefore, demonstration of adequate scram times at reactor steam dome pressure ≥ 800 psig ensures that the measured scram times will be within the specified limits at higher pressures. Limits are specified as a function of reactor pressure to account for the sensitivity of the scram insertion times with pressure and to allow a range of pressures over which scram time testing can be performed. To ensure that scram time testing is performed within a reasonable time following ~~fuel movement within the reactor pressure vessel or after~~ a shutdown ≥ 120 days or longer, control rods are required to be tested before exceeding 40% RTP. ~~In the event fuel movement is limited to selected core cells, it is the intent of this SR that only those CRDs associated with the core cells affected by the fuel movements are required to be scram time tested.~~ This Frequency is acceptable considering the additional surveillances performed for control rod OPERABILITY, the frequent verification of adequate accumulator pressure, and the required testing of control rods affected by fuel movement within the affected fuel cell and by work on control rods or the CRD System.

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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BASES

SURVEILLANCE REQUIREMENTS (continued)

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, required by footnote (b), are included in the Technical Requirements Manual (Ref. 7) and are established based on a high probability of meeting the acceptance criteria at reactor pressures ≥ 800 psig. The limits for reactor pressures ≥ 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."

Specific examples of work that could affect the scram times are (but are not limited to) the following: removal of any CRD for maintenance or modification; replacement of a control rod; and maintenance or modification of a scram solenoid pilot valve, scram valve, accumulator, isolation valve or check valve in the piping required for scram.

The Frequency of once prior to declaring the affected control rod OPERABLE is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

SR 3.1.4.4

or when fuel movement within the reactor pressure vessel occurs,

When work that could affect the scram insertion time is performed on a control rod or CRD System, testing must be done to demonstrate each affected control rod is still within the limits of Table 3.1.4-1 with the reactor steam dome pressure ≥ 800 psig. Where work has been performed at high reactor pressure, the requirements of SR 3.1.4.3 and SR 3.1.4.4 can be satisfied with one test. However, for a control rod affected by work performed while shutdown, a zero pressure test and a high pressure test may be required. This testing ensures that, prior to withdrawing the control rod for continued operation, the control rod scram performance is acceptable for operating reactor pressure conditions. Alternatively, a control rod scram test during hydrostatic pressure testing could also satisfy both criteria.

When fuel movement within the reactor pressure vessel occurs, only those control rods associated with the core cells affected by the fuel movement are required to be scram time tested. During a routine refueling outage, it is expected that all control rods will be affected.

(continued)

No change. Included for information only.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.4 (continued)

The Frequency of once prior to exceeding 40% RTP is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

This test is also used to demonstrate control rod OPERABILITY when ≥ 40% RTP after work that could affect the scram insertion time is performed on the CRD system.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.
2. FSAR, Section 3.4.
3. FSAR, Appendix M.
4. FSAR, Sections 14.3 and 14.4.
5. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," (revision specified in the COLR).
6. Letter from R. F. Janecek (BWROG) to R. W. Starostecki (NRC), "BWR Owners' Group Revised Reactivity Control Systems Technical Specifications", BWROG-8754, September 17, 1987.
7. Technical Requirements Manual, Table T5.0-1.
8. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

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BASES (continued)

ACTIONS

A.1

If the sodium pentaborate solution concentration is not within the 10 CFR 50.62 limits (not within Region A of Figure 3.1.7-1 or 3.1.7-2), but greater than original licensing basis limits (within Region B of Figure 3.1.7-1 or 3.1.7-2), the solution must be restored to within Region A limits in 72 hours. It should be noted that the lowest acceptable concentration in Region B is 5%. It is not necessary under these conditions to enter Condition C for both SLC subsystems inoperable, since the SLC subsystems are capable of performing their original design basis functions. Because of the low probability of an event and the fact that the SLC System capability still exists for vessel injection under these conditions, the allowed Completion Time of 72 hours is acceptable and provides adequate time to restore concentration to within limits. ~~The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of concentration out of limits or inoperable SLC subsystems during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, an SLC subsystem is inoperable and that subsystem is subsequently returned to OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total duration of 10 days (7 days in Condition B, followed by 3 days in Condition A), since initial failure of the LCO, to restore the SLC System. Then an SLC subsystem could be found inoperable again, and concentration could be restored to within limits. This could continue indefinitely.~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock," resulting in establishing the "time zero" at the time the LCO was initially not met instead of at the time Condition A was entered. The 10 day Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~

B.1

If one SLC subsystem is inoperable for reasons other than Condition A, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystem is adequate to perform the shutdown function and provide adequate buffering agent to the suppression pool. However, the overall reliability is reduced because a single failure in the remaining OPERABLE subsystem could result in reduced SLC System capability. The 7 day Completion Time is based on the availability of an OPERABLE subsystem capable of performing the

(continued)

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BASES

ACTIONS

B.1 (continued)

intended SLC System functions and the low probability of a DBA or severe transient occurring requiring SLC injection. ~~The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of concentration out of limits or inoperable SLC subsystems during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, concentration is out of limits, and is subsequently returned to within limits, the LCO may already have been not met for up to 3 days. This situation could lead to a total duration of 10 days (3 days in Condition A, followed by 7 days in Condition B), since initial failure of the LCO, to restore the SLC System. Then concentration could be found out of limits again, and the SLC subsystem could be restored to OPERABLE. This could continue indefinitely.~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock," resulting in establishing the "time zero" at the time the LCO was initially not met instead of at the time Condition B was entered. The 10 day Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~

C.1

If both SLC subsystems are inoperable for reasons other than Condition A, at least one subsystem must be restored to OPERABLE status within 8 hours. The allowed Completion Time of 8 hours is considered acceptable given the low probability of a DBA or transient occurring requiring SLC injection.

D.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 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.

(continued)

No change. Included for information only.

BASES

ACTIONS (continued)

I.2

The alternate method to detect and suppress oscillations implemented in accordance with Required Action I.1 was evaluated based on use up to 120 days (Ref. 12). The evaluation, based on engineering judgment, concluded that the likelihood of an instability event that could not be adequately handled by the alternate method during this 120 day period is negligibly small. The 120 day period is intended to be an outside limit to allow for the case where design changes or extensive analysis may be required to understand or correct some unanticipated characteristic of the instability detection algorithm or equipment. This action is not intended to be, and was not evaluated as, a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to normally be accomplished within the Completion Times allowed for Required Actions for Conditions A and B.

SURVEILLANCE REUIREMENTS

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column of Table 3.3.1.1-1.

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 RPS 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. 9) 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 RPS will trip when necessary.

SR 3.3.1.1.1

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 other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations

(continued)

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BASES

SURVEILLANCE REUIREMENTS

SR 3.3.1.1.1 (continued)

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 limit.

INSERT - BASES SR 3.3.1.1.1

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

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

A restriction to satisfying this SR when < 24% RTP is provided that requires the SR to be met only at ≥ 24% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 24% 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 ≥ 24% RTP, the Surveillance is required to have been satisfactorily performed in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 24% if the Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 24% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

(continued)

INSERT – BASES SR 3.3.1.1.1

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The agreement criteria includes an expectation of one decade of overlap when transitioning between neutron flux instrumentation. The overlap between SRMs and IRMs must be demonstrated prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs. This will ensure that reactor power will not be increased into a neutron flux region without adequate indication. The overlap between IRMs and APRMs is of concern when reducing power into the IRM range (entry into MODE 2 from MODE 1). 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. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above mid-scale on range 1 before SRMs have reached the upscale rod block.

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.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.3

(Not used.)

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 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.

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

SR 3.3.1.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.6 and SR 3.3.1.1.7

(Not used.)

~~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~~

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

~~SR 3.3.1.1.6 and SR 3.3.1.1.7 (continued)~~

~~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. Overlap between the SRMs and IRMs similarly exists when, prior to withdrawing an SRM from the fully inserted position, its associated IRMs have cleared their downscale rod block Allowable Values, prior to the SRM having reached its upscale rod block Allowable Value. Plant procedures should be consulted to determine the associated detectors.~~

~~As noted, SR 3.3.1.1.7 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~~.

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

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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B 3.3 INSTRUMENTATION

B 3.3.1.2 Source Range Monitor (SRM) Instrumentation

BASES

BACKGROUND

The SRMs provide the operator with information relative to the neutron flux level at very low flux levels in the core. As such, the SRM indication is used by the operator to monitor the approach to criticality and determine when criticality is achieved. The SRMs are maintained fully inserted until the count rate is greater than a minimum allowed count rate (a control rod block is set at this condition). After SRM to intermediate range monitor (IRM) overlap is demonstrated (as required by ~~SR 3.3.1.1.6~~ SR 3.3.1.1.1), the SRMs are normally fully withdrawn from the core.

The SRM subsystem of the Neutron Monitoring System (NMS) consists of four channels. Each of the SRM channels can be bypassed, but only one at any given time, by the operation of a bypass switch. Each channel includes one detector that can be physically positioned in the core. Each detector assembly consists of a miniature fission chamber with associated cabling, signal conditioning equipment, and electronics associated with the various SRM functions. The signal conditioning equipment converts the current pulses from the fission chamber to analog DC currents that correspond to the count rate. Each channel also includes indication, alarm, and control rod blocks. However, this LCO specifies OPERABILITY requirements only for the monitoring and indication functions of the SRMs.

During refueling, shutdown, and low power operations, the primary indication of neutron flux levels is provided by the SRMs or special movable detectors connected to the normal SRM circuits. The SRMs provide monitoring of reactivity changes during fuel or control rod movement and give the control room operator early indication of subcritical multiplication that could be indicative of an approach to criticality.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling and low power operation is provided by LCO 3.9.1, "Refueling Equipment Interlocks"; LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"; LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"; IRM Neutron Flux - High and Average Power Range Monitor (APRM) Neutron Flux - High (Setdown) Functions; and LCO 3.3.2.1, "Control Rod Block Instrumentation."

(continued)

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BASES

LCO (continued)

indication can be generated. These special detectors provide more flexibility in monitoring reactivity changes during fuel loading, since they can be positioned anywhere within the core during refueling. They must still meet the location requirements of SR 3.3.1.2.2 and all other required SRs for SRMs.

For an SRM channel to be considered OPERABLE, it must be providing neutron flux monitoring indication.

APPLICABILITY

The SRMs are required to be OPERABLE in MODES 2, 3, 4, and 5 prior to the IRMs being on scale on Range 3 to provide for neutron monitoring. In MODE 1, the APRMs provide adequate monitoring of reactivity changes in the core; therefore, the SRMs are not required. In MODE 2, with IRMs on Range 3 or above, the IRMs provide adequate monitoring and the SRMs are not required.

ACTIONS

A.1 and B.1

In MODE 2, with the IRMs on Range 2 or below, SRMs provide the means of monitoring core reactivity and criticality. With any number of the required SRMs inoperable, the ability to monitor neutron flux is degraded. Therefore, a limited time is allowed to restore the inoperable channels to OPERABLE status.

Provided at least one SRM remains OPERABLE, Required Action A.1 allows 4 hours to restore the required SRMs to OPERABLE status. This time is reasonable because there is adequate capability remaining to monitor the core, there is limited risk of an event during this time, and there is sufficient time to take corrective actions to restore the required SRMs to OPERABLE status or to establish alternate IRM monitoring capability. During this time, control rod withdrawal and power increase is not precluded by this Required Action. Having the ability to monitor the core with at least one SRM, proceeding to IRM Range 3 or greater (with overlap ~~required~~ ~~by~~ ~~SR 3.3.1.1.6~~), and thereby exiting the Applicability of this LCO, is acceptable for ensuring adequate core monitoring and allowing continued operation.

verified

SR 3.3.1.1.1

With three required SRMs inoperable, Required Action B.1 allows no positive changes in reactivity (control rod withdrawal must be immediately suspended) due to inability to monitor the changes. Required Action A.1 still applies and allows 4 hours to restore

(continued)

No change. Included for information only.

BASES

ACTIONS

A.1 and B.1 (continued)

monitoring capability prior to requiring control rod insertion. This allowance is based on the limited risk of an event during this time, provided that no control rod withdrawals are allowed, and the desire to concentrate efforts on repair, rather than to immediately shut down, with no SRMs OPERABLE.

C.1

In MODE 2, if the required number of SRMs is not restored to OPERABLE status within the allowed Completion Time, the reactor shall be placed in MODE 3. With all control rods fully inserted, the core is in its least reactive state with the most margin to criticality. 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.

D.1 and D.2

With one or more required SRMs inoperable in MODE 3 or 4, the neutron flux monitoring capability is degraded or nonexistent. The requirement to fully insert all insertable control rods ensures that the reactor will be at its minimum reactivity level while no neutron monitoring capability is available. Placing the reactor mode switch in the shutdown position prevents subsequent control rod withdrawal by maintaining a control rod block. The allowed Completion Time of 1 hour is sufficient to accomplish the Required Action, and takes into account the low probability of an event requiring the SRM occurring during this interval.

E.1 and E.2

With one or more required SRMs inoperable in MODE 5, the ability to detect local reactivity changes in the core during refueling is degraded. CORE ALTERATIONS must be immediately suspended and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Suspending CORE ALTERATIONS prevents the two most probable causes of reactivity changes, fuel loading and control rod withdrawal, from occurring. Inserting all insertable control rods ensures that the reactor will be at its minimum reactivity given that fuel is present in the

(continued)

Penetration Flow Path

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BASES

LCO
(continued)

6. Primary Containment Isolation Valve (PCIV) Position

PCIV position is provided for verification of containment integrity. In the case of PCIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active PCIV in a containment penetration flow path, i.e., two total channels of PCIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE. The indication for each PCIV consists of green and red indicator lights that illuminate to indicate whether the PCIV is fully open, fully closed, or in a mid-position. Therefore, the PAM specification deals specifically with this portion of the instrumentation channel.

Each penetration is treated separately and each penetration flow path is considered a separate function. Therefore, separate Condition entry is allowed for each inoperable penetration flow path.

7., 8. (Deleted)

9. Suppression Pool Water Temperature

Suppression pool water temperature is a Type A variable provided to detect a condition that could potentially lead to containment breach and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature

(continued)

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BASES

LCO

9. Suppression Pool Water Temperature (continued)

instrumentation allows operators to detect trends in suppression pool water temperature in sufficient time to take action to prevent steam quenching vibrations in the suppression pool. Fifteen active RTD elements are used for RG 1.97 compliance. Eleven of these devices are grouped together to provide an average measure of the upper region of the suppression pool. These input to a single recorder. The other four RTDs are used to measure the lower region of the suppression pool and are spaced almost equilaterally. They input to two recorders. However, to ensure the average temperature of the suppression pool is monitored, only two of these RTDs per quadrant are needed, since other means are available to ensure the average bulk suppression pool temperature is known if a few of the RTDs are inoperable. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channels.

Each suppression pool quadrant is treated separately and temperature indication in each suppression pool quadrant is considered a separate function. Therefore, separate Condition entry is allowed for each suppression pool quadrant with inoperable water temperature indication.

10. Drywell Temperature in the Vicinity of Reactor Vessel Level Instrument Reference Leg

Drywell temperature in the vicinity of reactor vessel level instrument reference legs is a Type A variable provided to measure drywell temperature so that proper compensation of reactor water level instruments can be accomplished. The drywell temperature is measured by six RTDs in the vicinity of the associated reference legs with the output being recorded on pen recorders in the control room. This is the primary indication used by the operator during an accident. Therefore, the PAM specification deals specifically with this portion of the instrumentation channel.

11. Diesel Generator Parameters

Diesel generator (DG) parameters are Type A variables provided to allow the operator to ensure proper operation of the DGs and to control the DGs post accident. Each of the four parameters (output voltage, output current, output power, and battery voltage) is monitored for each of the two unit specific DGs and the swing DG and is read on indicators in the control room. These are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channels.

(continued)

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BASES

BACKGROUND (continued)

5. Reactor Water Cleanup System Isolation

The Reactor Vessel Water Level - Low Low, Level 2 Isolation Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into two two-out-of-two trip systems. The Area Temperature - High Function receives input from six temperature monitors, three to each trip system. The Area Ventilation Differential Temperature - High Function receives input from six differential temperature monitors, three in each trip system. These are configured so that any one input will trip the associated trip system. Each of the two trip systems is connected to one of the two valves on the RWCU penetration. However, the SLC System Initiation Function only provides an input to one trip system, thus closes only one valve.

RWCU Functions isolate the Group 5 valves.

6. RHR Shutdown Cooling System Isolation

The Reactor Vessel Water Level - Low, Level 3 Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected to two two-out-of-two trip systems.

The Reactor Vessel Pressure - High Function receives input from two channels, with each channel in one trip system using a one-out-of-one logic. Each of the two trip systems is connected to one of the two valves on the shutdown cooling penetration.

RHR Shutdown Cooling System Isolation Functions isolate the Group 6 valves. The outboard shutdown cooling isolation valve, 1E11-F009, while not a PCIV, isolates on the same signals which isolate Group 6 valves.

INSERT - Bases 3.3.6.1 Background

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the primary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves to limit offsite doses. Refer to LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Applicable Safety Analyses Bases for more detail of the safety analyses.

Primary containment isolation instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 6). Certain instrumentation Functions

(continued)

INSERT 1 – Bases 3.3.6.1 Background

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7. Traversing Incore Probe (TIP) System Isolation

The Reactor Vessel Water Level – Low, Level 3 Isolation Function receives input from two reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into one two-out-of-two logic trip system. The Drywell Pressure – High Isolation function receives input from two drywell pressure channels. The outputs from the drywell pressure channels are connected into one two-out-of-two logic trip system.

When either isolation Function actuates, the TIP drive mechanisms will withdraw the TIPs, if inserted, and close the inboard TIP system isolation ball valves when the TIPs are fully withdrawn. The outboard TIP system isolation valves are manual shear valves.

TIP System Isolation Functions isolate the Group 13 valves (inboard isolation ball valves).

No change. Included for information only.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.d. Reactor Vessel Water Level - Low Low, Level 2 (continued)

The Reactor Vessel Water Level - Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level - Low Low, Level 2 Allowable Value (LCO 3.3.5.1), since the capability to cool the fuel may be threatened.

This Function isolates the Group 5 valves.

6. RHR Shutdown Cooling System Isolation

6.a. Reactor Steam Dome Pressure - High

The Reactor Steam Dome Pressure - High Function is provided to isolate the shutdown cooling portion of the Residual Heat Removal (RHR) System. This interlock is provided only for equipment protection to prevent an intersystem LOCA scenario, and credit for the interlock is not assumed in the accident or transient analysis in the FSAR.

The Reactor Steam Dome Pressure - High signals are initiated from two transmitters that are connected to different taps on the RPV. Two channels of Reactor Steam Dome Pressure - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Function is only required to be OPERABLE in MODES 1, 2, and 3, since these are the only MODES in which the reactor can be pressurized; thus, equipment protection is needed. The Allowable Value was chosen to be low enough to protect the system equipment from overpressurization.

This Function isolates the Group 6 valves (and 1E11-F009).

6.b. Reactor Vessel Water Level - Low, Level 3

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level - Low, Level 3 Function associated with RHR Shutdown Cooling System isolation is not directly assumed in safety analyses because a break of the RHR Shutdown Cooling System is bounded by breaks of the recirculation and MSL. The

(continued)

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6.b. Reactor Vessel Water Level - Low, Level 3 (continued)

RHR Shutdown Cooling System isolation on Level 3 supports actions to ensure that the RPV water level does not drop below the top of the active fuel during a vessel draindown event caused by a leak (e.g., pipe break or inadvertent valve opening) in the RHR Shutdown Cooling System. The top of active fuel is defined in "Applicable Safety Analyses" for Safety Limit 2.1.1.3, "Reactor Vessel Water Level," found in the Bases for Safety Limit 2.1.1, "Reactor Core SLs."

Reactor Vessel Water Level - Low, Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of the Reactor Vessel Water Level - Low, Level 3 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted [footnote (d) to Table 3.3.6.1-1], only two channels of the Reactor Vessel Water Level - Low, Level 3 Function are required to be OPERABLE in MODES 4 and 5 (and must input into the same trip system), provided the RHR Shutdown Cooling System integrity is maintained. System integrity is maintained provided the piping is intact and no maintenance is being performed that has the potential for draining the reactor vessel through the system.

The Reactor Vessel Water Level - Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level - Low, Level 3 Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level - Low, Level 3 Function is only required to be OPERABLE in MODES 3, 4, and 5 to prevent this potential flow path from lowering the reactor vessel level to the top of the fuel. In MODES 1 and 2, another isolation (i.e., Reactor Steam Dome Pressure - High) and administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

This Function isolates the Group 6 valves (and 1E11-F009).

INSERT - Bases 3.3.6.1 ASA

Note 2

ACTIONS

~~A Note~~ has been provided to modify the ACTIONS related to primary containment isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered,

INSERT - Bases 3.3.6.1 Actions

(continued)

Traversing Incore Probe System Isolation

7.a. Reactor Vessel Water Level — Low, Level 3

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 3 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Reactor Vessel Water Level — Low, Level 3 Function associated with isolation is implicitly assumed in the FSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level — Low, Level 3 signals are initiated from level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Two channels of Reactor Vessel Water Level — Low, Level 3 Function are available and are required to be OPERABLE to ensure that no single instrument failure can initiate an inadvertent isolation actuation. The isolation function is ensured by the manual shear valve in each penetration.

The Reactor Vessel Water Level — Low, Level 3 Allowable Value was chosen to be the same as the RPS Level 3 scram Allowable Value (LCO 3.3.1.1), since isolation of these valves is not critical to orderly plant shutdown.

This Function isolates the Group 13 valves.

7.b. Drywell Pressure — High

High drywell pressure can indicate a break in the RCPB inside the primary containment. The isolation of some of the primary containment isolation valves on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Drywell Pressure — High Function, associated with isolation of the primary containment, is implicitly assumed in the FSAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Two channels of Drywell Pressure — High per Function are available and are required to be OPERABLE to ensure that no single instrument failure can initiate an inadvertent actuation. The isolation function is ensured by the manual shear valve in each penetration.

The Allowable Value was selected to be the same as the ECCS Drywell Pressure — High Allowable Value (LCO 3.3.5.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 13 valves.

INSERT – Bases 3.3.6.1 Actions

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The ACTIONS are modified by two Notes. Note 1 allows penetration flow path(s) to be unisolated intermittently under administrative controls. 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 primary containment isolation is indicated.

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

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.

E.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 2 within 6 hours.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

F.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels.

For the RWCU Area and Area Ventilation Differential Temperature - High Functions, the affected penetration flow path(s) may be considered isolated by isolating only that portion of the system in the associated room monitored by the inoperable channel. That is, if the RWCU pump room A area channel is inoperable, the pump room A area can be isolated while allowing continued RWCU operation utilizing the B RWCU pump.

Alternately, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition ~~G~~ H must be entered and its Required Actions taken.

The 1 hour Completion Time is acceptable, because it minimizes risk while allowing sufficient time for personnel to isolate the affected penetration flow path(s).

(continued)

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BASES

INSERT - BASES 3.3.6.1 Condition G

ACTIONS (continued)

~~G.1 and G.2~~ H.1 and H.2

or G

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, or any Required Action of Condition F is not met and the associated Completion Time has expired, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

~~H.1 and H.2~~ I.1 and I.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the SLC System is declared inoperable or the RWCU System is isolated. Since this Function is required to ensure that the SLC System performs its intended function, sufficient remedial measures are provided by declaring the SLC System inoperable or isolating the RWCU System.

The 1 hour Completion Time is acceptable because it minimizes risk while allowing sufficient time for personnel to isolate the RWCU System.

~~I.1 and I.2~~ J.1 and J.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated penetration flow path should be closed. However, if the shutdown cooling function is needed to provide core cooling, these Required Actions allow the penetration flow path to remain unisolated provided action is immediately initiated to restore the channel to OPERABLE status or to isolate the RHR Shutdown Cooling System (i.e., provide alternate decay heat removal capabilities so 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.

(continued)

INSERT – Bases 3.3.6.1 Condition G

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G.1 and G.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels. The 24 hour Completion Time is acceptable due to the fact that the TIP System penetration is a small bore (approximately ½ inch), its isolation in a design basis event (with loss of offsite power) would be via the manually operated shear valves, and the ability to manually isolate by either the normal isolation valve or the shear valve is unaffected by the inoperable instrumentation. Alternately, if it is not desired to isolate the affected penetration flow path(s), Condition H must be entered and its Required Actions taken.

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BASES

LCO (continued)

subsystems and ADS must therefore be OPERABLE to satisfy the single failure criterion required by Reference 10. (Reference 9 takes no credit for HPCI.) HPCI must be OPERABLE due to risk consideration.

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR low pressure permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3, when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, when reactor steam dome pressure is ≤ 150 psig, ADS and HPCI are not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS - Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of LCO 3.0.4.b, which allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

or if one LPCI pump in both LPCI subsystems is inoperable,

subsystem(s)

If any one low pressure ECCS injection/spray subsystem is inoperable, the inoperable ~~subsystem~~ must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is

(continued)

No change. Included for information only.

BASES

ACTIONS

A.1 (continued)

based on a reliability study (Ref. 11) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

B.1 and B.2

If the inoperable low pressure ECCS subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to 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.

C.1 and C.2

If the HPCI System is inoperable and the RCIC System is verified to be OPERABLE, the HPCI System must be restored to OPERABLE status within 14 days. In this condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY within 1 hour is therefore required when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be verified, however, Condition E must be immediately entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on a reliability study cited in Reference 11 and has been found to be acceptable through operating experience.

(continued)

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BASES

ACTIONS

D.1 and D.2

, or one LPCI pump in both LPCI subsystems,

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to an inoperable HPCI System, the inoperable low pressure ECCS injection/spray subsystem or the HPCI System must be restored to OPERABLE status within 72 hours. In this condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is significantly reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since both a high pressure system (HPCI) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the HPCI System or the low pressure ECCS injection/spray subsystem to OPERABLE status. This Completion Time is based on a reliability study cited in Reference 11 and has been found to be acceptable through operating experience.

E.1 and E.2

With one ADS valve inoperable, no action is required, because an analysis demonstrated that the remaining six ADS valves are capable of providing the ADS function, per Reference 13.

If any Required Action and associated Completion Time of Condition C or D 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. Entry into MODE 3 is not required if the reduction in reactor steam dome pressure to ≤ 150 psig results in exiting the Applicability for the Condition, and the ≤ 150 psig is achieved within the given 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

F

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.

(continued)

No change. Included for information only.

ACTIONS (continued)

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable except for inoperability due to leakage not within a limit specified in an SR to this LCO, the affected penetration flow paths must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured.

For a penetration isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available valve to the primary containment. The device must be subjected to leakage testing requirements equivalent to the inoperable valve. For example: 1) if the inoperable valve is required to be Type C tested per 10 CFR 50, Appendix J, Option B (Ref. 4), the device chosen to isolate the penetration must also be subjected to Appendix J, Option B, Type C testing; and 2) if the inoperable valve is not subjected to Appendix J, Option B, testing ("-" in Reference 2, Table T7.0-1, Test Type column), the isolation device does not have to be subjected to Appendix J, Option B, testing.

If a valve is inoperable due to isolation time not within limits or other condition that would not be expected to adversely affect leakage characteristics, the inoperable valve may be used to isolate the penetration.

The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside containment

(continued)

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BASES

ACTIONS

A.1 and A.2 (continued)

and capable of potentially being mispositioned are in the correct position. The Completion Time of "Once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "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" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

two notes. Note 1

Required Action A.2 is modified by ~~a Note that~~ applies to isolation devices located in high radiation areas, and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

INSERT - BASES 3.6.1.3
Action A

B.1

With one or more penetration flow paths with two PCIVs inoperable except due to leakage not within limits, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. The device must be subjected to leakage testing requirements equivalent to the inoperable valve. For example: 1) if the inoperable valve is required to be Type C tested per 10 CFR 50, Appendix J, Option B, the device chosen to isolate the penetration must also be subjected to Appendix J, Option B, Type C testing; and 2) if the inoperable valve is not subjected to Appendix J, Option B, testing ("-" in Reference 2, Table T7.0-1, Test Type column), the isolation device does not have to be subjected to Appendix J, Option B, testing.

(continued)

INSERT – BASES 3.6.1.3 Action A

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Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

No change. Included for information only.

BASES

ACTIONS

B.1 (continued)

If a valve is inoperable due to isolation time not within limits or other condition that would not be expected to adversely affect leakage characteristics, the inoperable valve may be used to isolate the penetration. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

C.1 and C.2

With one or more penetration flow paths with one PCIV inoperable, except due to leakage not within limits, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. The device must be subjected to leakage testing requirements equivalent to the inoperable valve, except for inoperable valves in the Core Spray and Low Pressure Coolant Injection (LPCI) systems. For example: 1) if the inoperable valve is required to be Type C tested per 10 CFR 50, Appendix J, Option B, the device chosen to isolate the penetration must also be subjected to Appendix J, Option B, Type C testing; and 2) if the inoperable valve is not subjected to Appendix J, Option B, testing ("-" in Reference 2, Table T7.0-1, Test Type column), the isolation device does not have to be subjected to Appendix J, Option B, testing. For Core Spray and LPCI system valve inoperability, the device chosen to isolate the affected penetration is not required to be tested per 10 CFR 50, Appendix J, Option B, leakage testing. This exception is based on the integrity of the system piping, which serves to minimize leakage into the secondary containment.

If a valve is inoperable due to isolation time not within limits or other condition that would not be expected to adversely affect leakage characteristics, the inoperable valve may be used to isolate the penetration.

(continued)

BASES

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ACTIONS

The Completion Time of 4 hours for PCIVs other than those in penetrations with a closed system and EFCVs is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY in MODES 1, 2, and 3.

The closed system must meet the requirements of Reference 7.

C.1 and C.2 (continued)

~~Required Action C.1 must be completed within 4 hours for lines other than excess flow check valve (EFCV) lines and 12 hours for EFCV lines.~~ The Completion Time of 4 hours is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The Completion Time of 12 hours is reasonable considering the instrument to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated.

for penetrations with a closed system

72

also

for EFCVs

72

The Completion Time of once per 31 days for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions.

two notes. Note 1

Required Action C.2 is modified by ~~a Note that~~ applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

INSERT - BASES 3.6.1.3 Action C

D.1

With the MSIV leakage rate not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 4 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation

(continued)

INSERT – BASES 3.6.1.3 Action C

TSTF-269

Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1 (continued)

Note stating that the SR is not required to be met when the 18 inch purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.3.2

and not locked, sealed, or otherwise secured

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment 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 require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside primary containment, and capable of being mispositioned, are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

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 isolation devices, once they have been verified to be in the proper position, is low. A second Note has been included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open.

SR 3.6.1.3.3

This SR verifies that each primary containment manual isolation valve and blind flange that is located inside primary containment and is

and not locked, sealed, or otherwise secured

(continued)

TSTF-45

BASES

TSTF-46

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.3 (continued)

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. For these isolation devices inside primary containment, the Frequency defined as "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" is appropriate since these isolation devices are operated under administrative controls and the probability of their misalignment is low.

This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

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 the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA and personnel safety reasons. Therefore, the probability of misalignment of these isolation devices, once they have been verified to be in their proper position, is low. A second Note has been included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open.

SR 3.6.1.3.4

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Actuation and monitoring circuitry is provided in the main control room. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. The circuitry is such that a light illuminates upon loss of explosive charge continuity. Ensuring that the light illuminates when voltage is applied and that it is extinguished when installed in the circuit provides assurance of explosive valve continuity. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.3.5

Verifying the isolation time of each power operated, ~~and each~~ automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full

(continued)

No change. Included for information only.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.5 (continued)

closure isolation time is demonstrated by SR 3.6.1.3.6. The isolation time test ensures that each valve will isolate in a time period less than or equal to that listed in the FSAR and that no degradation affecting valve closure since the performance of the last Surveillance has occurred. (EFCVs are not required to be tested because they have no specified time limit). The Frequency of this SR is 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 analyses. This ensures that the calculated radiological consequences of these events remain within 10 CFR 50.67 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 SR 3.3.6.1.6 overlaps this SR to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.3.8

This SR requires a demonstration that each reactor instrumentation line excess flow check valve (EFCV) (of a representative sample) is OPERABLE by verifying that the valve reduces flow to within limits on an actual or simulated instrument line break condition. (The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested. In addition, the EFCVs

(continued)

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BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.13

This SR ensures that the leakage rate of secondary containment bypass leakage paths is less than the specified leakage rate. This provides assurance that the assumptions in the radiological evaluations that form the basis of the FSAR (Ref. 1) are met. The secondary containment bypass leakage paths are: 1) main steam condensate drain, penetration 8; 2) reactor water cleanup, penetration 14; 3) equipment drain sump discharge, penetration 18; 4) floor drain sump discharge, penetration 19; 5) HPCI steam line condensate to main condenser, penetration 11; and 6) RCIC steam line condensate to main condenser, penetration 10. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. The Frequency is required by the Primary Containment Leakage Rate Testing Program (Ref. 6).

REFERENCES

1. Unit 2 FSAR, Section 15.3.
2. Technical Requirements Manual, Table T7.0-1.
3. FSAR, Section 5.2.
4. 10 CFR 50, Appendix J, Option B.
5. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.
6. Primary Containment Leakage Rate Testing Program.
7. FSAR, Section 5.2.2.5.1

ACTIONS (continued)

C.1

Suppression pool average temperature is allowed to be > 100°F when any OPERABLE IRM channel is > 25/40 divisions of full scale on Range 7, and when testing that adds heat to the suppression pool is being performed. However, if temperature is > 105°F, all testing must be immediately suspended to preserve the heat absorption capability of the suppression pool. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1, D.2, and D.3

Suppression pool average temperature > 110°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further, cooldown to MODE 4 is required at normal cooldown rates (provided pool temperature remains ≤ 120°F). Additionally, when suppression pool temperature is > 110°F, increased monitoring of pool temperature is required ~~to ensure that it remains ≤ 120°F~~. The once per 30 minute Completion Time is adequate, based on operating 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. Additionally, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 4 within 36 hours.

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~~ Time is 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 and local temperatures could be exceeded very quickly.

(continued)

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BASES

ACTIONS

C.1, C.2, and C.3 (continued)

case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1 and SR 3.6.4.1.2

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 3.6.4.1.1 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. An access opening contains one inner and one outer door. The intent is not to breach the secondary containment at any time when secondary containment is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times. However, all secondary containment access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being performed on an access opening. When the secondary containment configuration excludes Zone I and/or Zone II, these SRs also include verifying the hatches and doors separating the common refueling floor zone from the reactor building(s). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

INSERT - BASES 3.6.4.1 SR

SR 3.6.4.1.3 and SR 3.6.4.1.4

~~The Unit 1 and Unit 2 SGT Systems exhaust the secondary containment atmosphere to the environment through appropriate treatment equipment. To ensure that all fission products are treated, SR 3.6.4.1.3 verifies that the appropriate SGT System(s) will rapidly establish and maintain a negative pressure in the secondary containment. This is confirmed by demonstrating that the required SGT subsystem(s) will draw down the secondary containment to ≥ 0.20 inch of vacuum water gauge in ≤ 120 seconds (13 seconds of diesel generator startup and breaker closing time is included in the 120 second drawdown time). This cannot be accomplished if the secondary containment boundary is not intact. SR 3.6.4.1.4~~

(continued)

INSERT – Bases 3.6.4.1 SR

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The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. The SGT System is designed to draw down pressure in the secondary containment to ≥ 0.20 inches of vacuum water gauge in ≤ 120 seconds and maintain pressure in the secondary containment at ≥ 0.20 inches of vacuum water gauge for 1 hour at a flow rate ≤ 4000 CFM. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.3 and SR 3.6.4.1.4 verify that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can rapidly be established and maintained. When the SGT System is operating as designed, the establishment and maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. Establishment of this pressure is confirmed by SR 3.6.4.1.3, which demonstrates that the secondary containment can be drawn down to ≥ 0.20 inches of vacuum water gauge in ≤ 120 seconds using the required SGT subsystem(s). SR 3.6.4.1.4 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.20 inches of vacuum water gauge for 1 hour using the required SGT subsystem(s) at a flow rate ≤ 4000 CFM. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. The primary purpose of these SRs is to ensure secondary containment boundary integrity. The secondary purpose of these SRs is to ensure that the SGT subsystem(s) being tested function as designed. There is a separate LCO with Surveillance Requirements which serves the primary purpose of ensuring OPERABILITY of the SGT System. These SRs need not be performed with each SGT subsystem. The SGT subsystem(s) used for these Surveillances are staggered to ensure that in addition to the requirements of LCO 3.6.4.3, the required SGT subsystem(s) will perform this test. The inoperability of the SGT System does not necessarily constitute a failure of these Surveillances relative to the secondary containment OPERABILITY.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.3 and SR 3.6.4.1.4 (continued)

~~demonstrates that the required SGT subsystem(s) can maintain ≥ 0.20 inch of vacuum water gauge for 1 hour at a flow rate ≤ 4000 cfm for each SGT subsystem. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. Therefore, these two tests are used to ensure secondary containment boundary integrity. Since these SRs are secondary containment tests, they 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, each SGT subsystem or combination of subsystems will perform this test.~~ The number of SGT subsystems and the required combinations are dependent on the configuration of the secondary containment and are detailed in the Technical Requirements Manual (Ref. 3). The Note to SR 3.6.4.1.3 and SR 3.6.4.1.4 specifies that the number of required SGT subsystems be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Subsection 14.4.3.

2. FSAR, Subsection 14.4.4.

3. Technical Requirements Manual, Section 8.0.

4. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

APPLICABLE SAFETY ANALYSES (continued)

containment so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The power operated, automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 3.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed, or open in accordance with appropriate administrative controls, automatic SCIVs are de-activated and secured in their closed position, and blind flanges are in place. These passive isolation valves or devices are listed in Reference 3.

The SCIVs required to be OPERABLE are dependent on the configuration of the secondary containment (which is dependent on the operating status of both units, as well as the configuration of doors, hatches, refueling floor plugs, and available flow paths to SGT Systems). The required boundary encompasses the zones which can be postulated to contain fission products from accidents required to be considered for the condition of each unit, and furthermore, must include zones not isolated from the SGT subsystems being credited for meeting LCO 3.6.4.3, "Standby Gas Treatment (SGT) System." The required SCIVs are those in penetrations communicating with the zones required for secondary containment OPERABILITY and are detailed in Reference 3.

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, the OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in

(continued)

No change. Included for information only.

BASES

APPLICABILITY (continued)

MODE 4 or 5, except for other situations under which significant radioactive releases can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment. (Note: Moving irradiated fuel assemblies in the secondary containment may also occur in MODES 1, 2, and 3.)

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated 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 isolation is indicated.

The second Note provides clarification that for the purpose of this LCO separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this Criterion are a closed and deactivated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment. The Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to

(continued)

BASES

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ACTIONS

A.1 and A.2 (continued)

isolate the penetration, and the probability of a DBA, which requires the SCIVs to close, occurring during this short time is very low.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time of once per 31 days is appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

two notes. Note 1

Required Action A.2 is modified by ~~a Note that~~ applies to devices located in high radiation areas and allows them to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment once they have been verified to be in the proper position, is low.

INSERT - BASES 3.6.4.2 Action A

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable considering the time required to isolate the penetration and the probability of a DBA, which requires the SCIVs to close, occurring during this short time, is very low.

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 to MODE 4 within 36 hours. The allowed Completion Times are

(continued)

INSERT – BASES 3.6.4.2 Action A

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Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

INSERT – BASES 3.6.1.3 Action A

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Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

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BASES

ACTIONS

C.1 and C.2 (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.

D.1, D.2, and D.3

If any Required Action and associated Completion Time of Condition A or B are not met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and the movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action D.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving fuel while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations.

Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

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 isolation devices in secondary containment that are capable of being mispositioned are in the correct position.

This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

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

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1 (continued)

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.

SR 3.6.4.2.2

Verifying that the isolation time of each power operated ~~and each~~ 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent 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 SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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BASES

ACTIONS

A.2 (continued)

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one required offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

~~The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a, b, or c. If Condition A is entered while, for instance, the swing DG is inoperable, and that DG is subsequently returned OPERABLE, LCO 3.8.1.a, b, or c may already have been not met for up to 14 days. This situation could lead to a total of 17 days, since initial failure to meet LCO 3.8.1.a, b, and c, to restore the offsite circuit. At this time, the swing DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 31 days) allowed prior to complete restoration of LCO 3.8.1.a, b, and c. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a, b, or c. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hours and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.~~

(continued)

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BASES

ACTIONS

~~A.3 (continued)~~

~~As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time LCO 3.8.1.a, b, or c was initially not met, instead of at the time that Condition A was entered.~~

B.1

To ensure a highly reliable power source remains with one Unit 1 or the swing DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a Unit 1 or swing DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable Unit 1 or swing DG exists; and

b. A redundant required feature on the other division (Division 1 or 2), or divisions in the case of the Unit 1 and 2 Standby Gas Treatment (SGT) System, is inoperable.

If, at any time during the existence of this Condition (one Unit 1 or swing DG inoperable), a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

BASES

(continued)

No change. Included for information only.

BASES

ACTIONS

B.4

Regulatory Guide 1.93 (Ref. 6) provides guidance that operation in Condition B may continue for 72 hours. A risk-informed, deterministic evaluation performed for Plant Hatch justifies operation in Condition B for 14 days, provided action is taken to ensure two DGs are dedicated to each Hatch unit. This is accomplished for an inoperable A or C DG by inhibiting the automatic alignment (on a LOCA or LOSP signal) of the swing DG to the other unit. If the inoperable DG is the swing DG, each unit has two dedicated DGs. For an inoperable swing DG, a 72 hour Completion Time applies unless the restrictions specified following this paragraph are satisfied. In Condition B for each defined Completion Time and restriction (if applicable), the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Unit 1 Class 1E Distribution System. The Completion Times take into account the capacity and capability of the remaining AC sources, reasonable time for maintenance, and low probability of a DBA occurring during this period. The 14 day Completion Time is also subject to additional restrictions for planned maintenance on other plant systems; these are controlled by 90AC-OAM-002-0. Use of the 14 day Completion time is permitted as follows :

- For the Unit 1 DGs:

  Once per DG per operating cycle for performing major overhaul of a DG.

  As needed to complete unplanned maintenance. This time shall be minimized.

- For the swing DG:

  The additional restrictions apply prior to using a Completion Time of greater than 72 hours.

  The 14 day Completion Time may be used once per Unit 1 operating cycle for performing a major overhaul of the swing DG.

  The time may be used as needed to complete unplanned maintenance. This time shall be minimized.

- As needed for the swing DG when it is inhibited from automatically aligning to Unit 1 in order for the 14 day Completion Time to be used for a Unit 2 DG.

(continued)

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BASES

ACTIONS

B.4 (continued)

The "AND" connector between the 72 hour and 14 day Completion Times means that both Completion Times apply simultaneously. That is, the 14 day Completion Time for an A or C DG with the swing DG inhibited applies from the time of entry into Condition B, not from the time the swing DG is inhibited.

~~The fourth Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a, b, or c. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, LCO 3.8.1.a, b, or c may already have been not met for up to 72 hours. This situation could lead to a total of 17 days, since initial failure to meet LCO 3.8.1.a, b, and c, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of LCO 3.8.1.a, b, and c. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a, b, or c. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connectors between the Completion Times mean that all Completion Times apply simultaneously, and the more restrictive must be met.~~

~~As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time that LCO 3.8.1.a, b, or c was initially not met, instead of the time that Condition B was entered.~~

C.1

To ensure a highly reliable power source remains with one required Unit 2 DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

(continued)

No change. Included for information only.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.5 (continued)

To minimize the wear on moving parts that do not get lubricated when the engine is not running, this SR has been modified by a Note (Note 1) to indicate that all DG starts for this Surveillance may be preceded by an engine prelube period and followed by a warmup prior to loading.

Note 2 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 3 modifies this Surveillance by stating that momentary load transients because of changing bus loads do not invalidate this test.

Note 4 indicates that this Surveillance is required to 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.

To minimize testing of the swing DG, Note 5 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units, with the DG started using the starting circuitry of one unit and synchronized to the ESF bus of that unit for one periodic test and started using the starting circuitry of the other unit and synchronized to the ESF bus of that unit during the next periodic test. This is allowed since the main purpose of the Surveillance, to ensure DG OPERABILITY, is still being verified on the proper frequency, and each unit's starting circuitry and breaker control circuitry, which is only being tested every second test (due to the staggering of the tests), historically have a very low failure rate. If the swing DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.6

Transfer of each 4.16 kV ESF 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

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. Credit may be taken for unplanned events that satisfy this SR.

INSERT 1 - BASES 3.8.1

This Surveillance tests the applicable logic associated with the Unit 1 swing bus. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with the Unit 2 swing bus. Consequently, a test must be performed within the normally Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1 or 2 does not have applicability to Unit 2. As the Surveillance represents separate tests, the Unit 1 Surveillance should not be performed with Unit 1 in MODE 1 or 2 and the Unit 2 test should not be performed with Unit 2 in MODE 1 or 2.

normally normally

SR 3.8.1.7

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The largest single load for DGs 1A and 1C is a core spray pump at rated flow (1275 bhp). For DG 1B, the largest single load is a residual heat removal service water pump at rated flow (1225 bhp). This Surveillance may be accomplished by: a) tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power or while solely supplying the bus, or b) tripping its associated single largest post-accident load with the DG solely supplying the bus. Although Plant Hatch Unit 1 is not committed to IEEE-387-1984 (Ref. 12), this SR is consistent with the IEEE-387-1984 requirement that states the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the

(continued)

Insert 1 - Bases 3.8.1

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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. For all DGs, this represents 65.5 Hz, equivalent to 75% of the difference between nominal speed and the overspeed trip setpoint.

The voltage and frequency specified are consistent with the nominal range for the DG. SR 3.8.1.7.a corresponds to the maximum frequency excursion, while SR 3.8.1.7.b is the voltage to which the DG must recover following load rejection. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for Note 1 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. Credit may be taken for unplanned events that satisfy this SR.

INSERT 1 - BASES 3.8.1

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing is performed with only the DG providing power to the associated 4160 V ESF bus. The DG is not synchronized with offsite power.

To minimize testing of the swing DG, Note 2 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit (no unit specific DG components are being tested). If the swing DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.8

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.88. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

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

This SR is modified by three Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Note 2 is provided in recognition that if the offsite electrical power distribution system is lightly loaded (i.e., system voltage is high), it may not be possible to raise voltage without creating an overvoltage condition on the ESF bus. Therefore, to ensure the bus voltage, supplied ESF loads, and DG are not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage or ESF bus loading does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable.

INSERT 1 - BASES 3.8.1

To minimize testing of the swing DG, Note 3 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit (no unit specific DG components are being tested). If the swing DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

(continued)

No change. Included for information only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

This Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source and is consistent with Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(1). This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start time of 12 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, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these 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. For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations.

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. The reason for Note 2 is that performing the Surveillance would remove a required

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. This Surveillance tests the applicable logic associated with the Unit 1 swing bus. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with the Unit 2 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 2. As the Surveillance represents separate tests, the Unit 1 Surveillance should not be performed with Unit 1 in MODE 1, 2, or 3 and the Unit 2 test should not be performed with Unit 2 in MODE 1, 2, or 3.

INSERT 2 - BASES 3.8.1

normally

normally

normally

SR 3.8.1.10

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (12 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, low pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these 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. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations.

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

(continued)

Insert 2 - Bases 3.8.1

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

BASES

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SURVEILLANCE REQUIREMENTS

TSTF-400

SR 3.8.1.10 (continued)

with the expected fuel cycle lengths. The 24 month Frequency is based on a review of the surveillance test history and Reference 15.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could potentially cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. This Surveillance tests the applicable logic associated with the Unit 1 swing bus. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with the Unit 2 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1 or 2 does not have applicability to Unit 2. As the Surveillance represents separate tests, the Unit 1 Surveillance should not be performed with Unit 1 in MODE 1 or 2 and the Unit 2 test should not be performed with Unit 2 in MODE 1 or 2.

INSERT 1 - BASES 3.8.1

normally

normally

normally

SR 3.8.1.11

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ECCS initiation signal ~~and critical protective functions (engine overspeed, generator differential current, and low lubricating oil pressure) are available to trip the DG to avert substantial damage to the DG unit~~. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

INSERT 3 - BASES 3.8.1

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

The SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from

(continued)

INSERT 3 – Bases 3.8.1

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Non-critical automatic trips are all automatic trips except: a) engine overspeed, b) generator differential current, and c) low lube oil pressure.

TSTF-283

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

INSERT 2 - BASES 3.8.1

service. Credit may be taken for unplanned events that satisfy this SR. This Surveillance tests the applicable logic associated with the Unit 1 swing bus. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with the Unit 2 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 2. As the Surveillance represents separate tests, the Unit 1 Surveillance should not be performed with Unit 1 in MODE 1 or 2 and the Unit 2 test should not be performed with Unit 2 in MODE 1, 2, or 3.

normally

normally

normally

SR 3.8.1.12

Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(3), 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 24 hours. The first 22 hours of this test are performed at ≥ 2775 kW and ≤ 2825 kW (which is near the continuous rating of the DG), and the last 2 hours of this test are performed at ≥ 3000 kW. This is in accordance with commitments described in FSAR Section 8.4 (Ref. 2). The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, and for gradual loading, discussed in SR 3.8.1.2, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor ≤ 0.88. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience. A load band 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.

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

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

This Surveillance has been modified by four 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. However, it is acceptable to perform this SR in MODES 1 and 2 provided the other two DGs are OPERABLE, since a perturbation can only affect one divisional DG. If during the performance of this Surveillance, one of the other DGs becomes inoperable, this Surveillance is to be suspended. The Surveillance may not be performed in MODES 1 and 2 during inclement weather and unstable grid conditions. Credit may be taken for unplanned events that satisfy this SR. Note 3 is provided in recognition that if the offsite electrical power distribution system is lightly loaded (i.e., system voltage is high), it may not be possible to raise voltage without creating an overvoltage condition on the ESF bus. Therefore, to ensure the bus voltage, supplied ESF loads, and DG are not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage or ESF bus loading does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable. To minimize testing of the swing DG, Note 4 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit (no unit specific DG components are being tested). If the swing DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

INSERT 1 - BASES 3.8.1

SR 3.8.1.13

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 12 seconds. The 12 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

TSTF-283

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

This SR is modified by three Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at near full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing. To minimize testing of the swing DG, Note 3 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit (no unit specific DG components are being tested). If the swing DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.14

This Surveillance is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(6), and ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the load sequence timers are reset.

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

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. This Surveillance tests the applicable logic associated with the Unit 1 swing bus. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with the Unit 2 swing bus. Consequently, a test must be performed within the

INSERT 2 - BASES 3.8.1

(continued)

TSTF-283

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

normally

Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 2. As the Surveillance represents separate tests, the Unit 1 Surveillance should not be performed with Unit 1 in MODE 1, 2, or 3 and the Unit 2 test should not be performed with Unit 2 in MODE 1, 2, or 3.

normally normally

SR 3.8.1.15

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. Although Plant Hatch Unit 1 is not committed to this standard, this SR is consistent with the provisions for automatic switchover required by IEEE-308 (Ref. 13), paragraph 6.2.6(2).

The intent in the requirements associated with SR 3.8.1.15.b is to show that the emergency loading is not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

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

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. This Surveillance tests the applicable logic associated with the Unit 1 swing bus. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with the Unit 2 swing bus. Consequently, a test must be performed within the

INSERT 2 - BASES 3.8.1

(continued)

TSTF-283

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

normally

Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 2. As the Surveillance represents separate tests, the Unit 1 Surveillance should not be performed with Unit 1 in MODE 1, 2, or 3 and the Unit 2 test should not be performed with Unit 2 in MODE 1, 2, or 3.

normally normally

SR 3.8.1.16

Under accident conditions, loads are sequentially connected to the bus by the automatic load sequence timing devices. 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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.

INSERT 2 - BASES 3.8.1

normally

This Surveillance tests the applicable logic associated with the Unit 1 swing bus. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with the Unit 2 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 2. As the Surveillance represents separate tests, the Unit 1 Surveillance should not be performed with Unit 1 in MODE 1, 2, or 3 and the Unit 2 test should not be performed with Unit 2 in MODE 1, 2, or 3.

normally normally

(continued)

TSTF-283

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

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, as discussed in the Bases for SR 3.8.1.9, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. 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. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations.

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. 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. This Surveillance tests the applicable logic associated with the Unit 1 swing bus. The comparable test specified in the Unit 2 Technical Specifications tests the applicable logic associated with the Unit 2 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 2. As the Surveillance represents separate tests, the Unit 1 Surveillance should not be performed with Unit 1 in MODE 1, 2, or 3 and the Unit 2 test should not be performed with Unit 2 in MODE 1, 2, or 3.

INSERT 2 - BASES 3.8.1

normally

normally

normally

SR 3.8.1.18

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously. For the purpose of this testing,

(continued)

No change. Included for information only.

BASES (continued)

ACTIONS

A.1

If one or more of the required Unit 2 AC or DC electrical power distribution subsystems are inoperable, and a loss of function has not occurred as described in Condition F, the remaining AC and DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could, however, result in the loss of certain safety functions (e.g., SGT System and LPCI valve load centers), continued power operation should not exceed 7 days. The 7 day Completion Time takes into account the capacity and capability of the remaining AC and DC electrical power distribution subsystems, and is based on the shortest restoration time allowed for the systems affected by the inoperable AC and DC electrical power distribution subsystem in the respective system Specification.

B.1

If a Unit 1 or swing DG DC electrical power distribution subsystem is inoperable, the remaining DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could, however, result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation should not exceed 12 hours. The 12 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining the DG DC electrical power distribution subsystem OPERABLE. (The DG DC electrical power distribution subsystem affects both the DG and the offsite circuit, as well as the breaker closure power for various 4160 VAC loads, but does not affect 125/250 VDC station service loads). The 12 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

a. There is a potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected bus(es) to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. [The redundant component is verified OPERABLE in accordance with Specification 5.5.10, "Safety Function Determination Program (SFDP)."]

(continued)

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BASES

ACTIONS

~~B.1 (continued)~~

~~The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.7.a. If Condition B is entered while, for instance, a Unit 1 or swing AC bus is inoperable and subsequently returned OPERABLE, LCO 3.8.7.a may already have been not met for up to 8 hours. This situation could lead to a total duration of 20 hours, since initial failure of LCO 3.8.7.a, to restore the Unit 1 and swing DG DC distribution system. At this time a Unit 1 or swing AC bus could again become inoperable, and Unit 1 and swing DG DC distribution system could be restored OPERABLE. This could continue indefinitely~~.

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time LCO 3.8.7.a was initially not met, instead of at the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet LCO 3.8.7.a indefinitely~~.

C.1

With one or more required Unit 1 or swing AC buses, load centers, motor control centers, or distribution panels in one subsystem inoperable, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

The Condition C postulated worst scenario is one 4160 V bus without AC power (i.e., no offsite power to the 4160 V bus and the associated DG inoperable). In this condition, the unit is more vulnerable to a complete loss of Unit 1 AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining buses by stabilizing the unit, and on restoring power to the affected buses. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

(continued)

ACTIONS

C.1 (continued)

a. There is a potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected bus(es) to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. [The redundant component is verified OPERABLE in accordance with Specification 5.5.10, "Safety Function Determination Program (SFDP)."]

~~The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.7.a. If Condition C is entered while, for instance, a Unit 1 station service DC bus is inoperable and subsequently returned OPERABLE, LCO 3.8.7.a may already have been not met for up to 2 hours. This situation could lead to a total duration of 10 hours, since initial failure of LCO 3.8.7.a, to restore the Unit 1 and swing AC distribution system. At this time a Unit 1 station service DC bus could again become inoperable, and Unit 1 and swing AC distribution system could be restored OPERABLE. This could continue indefinitely.~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time LCO 3.8.7.a was initially not met, instead of at the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet LCO 3.8.7.a indefinitely.~~

D.1

With one Unit 1 station service DC bus inoperable, the remaining DC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required Unit 1 DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

(continued)

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BASES

ACTIONS

D.1 (continued)

Condition D represents one Unit 1 division without adequate DC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation the plant is significantly more vulnerable to a complete loss of all Unit 1 station service DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining division, and restoring power to the affected division.

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without DC power, while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

~~The second Completion Time for Required Action D.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.7.a. If Condition D is entered while, for instance, Unit 1 or swing AC bus is inoperable and subsequently restored OPERABLE, LCO 3.8.7.a may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of LCO 3.8.7.a, to restore the Unit 1 station service DC distribution system. At this time, Unit 1 or swing AC bus could again become inoperable, and Unit 1 station service DC distribution system could be restored OPERABLE. This could continue indefinitely.~~

(continued)

TSTF-439

BASES

ACTIONS

~~D.1 (continued)~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time LCO 3.8.7.a was initially not met, instead of at the time Condition D was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.~~

E.1 and E.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit 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.

F.1

Condition F 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

No change. Included for information only.

BASES

LCO 3.0.5 (continued)

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the SRs.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of an SR on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of an SR on another channel in the same trip system.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs

(continued)

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BASES

LCO 3.0.6 (continued)

entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.10, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon failure to meet two or more LCOs concurrently, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross division checks to identify a loss of safety function for those support systems that support safety systems are required. The cross division check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

INSERT - LCO 3.0.6 Bases

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Special Operations LCOs in Section 3.10 allow specified TS requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Special Operations LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Special Operations LCOs is optional. A special operation may be performed either under the provisions of the appropriate Special Operations LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Special Operations LCO, the requirements of the

(continued)

INSERT – LCO 3.0.6 Bases

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operation is being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restriction for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

When a loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately addresses the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

No change. Included for information only.

BASES

LCO (continued)

This LCO applies only to OPERABLE control rods since inoperable control rods will be inserted and disarmed (LCO 3.1.3). Slow scramming control rods may be conservatively declared inoperable and not accounted for as "slow" control rods.

APPLICABILITY

In MODES 1 and 2, a scram is assumed to function during transients and accidents analyzed for these plant conditions. These events are assumed to occur during startup and power operation; therefore, the scram function of the control rods is required during these MODES. In MODES 3 and 4, with the mode switch in shutdown control rod block prevents withdrawal of control rods. This provides adequate requirements for control rod scram capability during these conditions. Scram requirements in MODE 5 are contained in LCO 3.9.5, "Control Rod OPERABILITY - Refueling."

ACTIONS

A.1

When the requirements of this LCO are not met, the rate of negative reactivity insertion during a scram may not be within the assumptions of the safety analysis. Therefore, 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. 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

The four SRs of this LCO are modified by a Note stating that during a single control rod scram time Surveillance, the CRD pumps shall be isolated from the associated scram accumulator. With the CRD pump isolated, (i.e., charging valve closed) the influence of the CRD pump head does not affect the single control rod scram times. During a full core scram, the CRD pump head would be seen by all control rods and would have a negligible effect on the scram insertion times.

SR 3.1.4.1

The scram reactivity used in DBA and transient analyses is based on an assumed control rod scram time. Measurement of the scram times with reactor steam dome pressure ≥ 800 psig demonstrates

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1 (continued)

acceptable scram times for the transients analyzed in References 3 and 4.

Maximum scram insertion times occur at a reactor steam dome pressure of approximately 800 psig because of the competing effects of reactor steam dome pressure and stored accumulator energy. Therefore, demonstration of adequate scram times at reactor steam dome pressure ≥ 800 psig ensures that the measured scram times will be within the specified limits at higher pressures. Limits are specified as a function of reactor pressure to account for the sensitivity of the scram insertion times with pressure and to allow a range of pressures over which scram time testing can be performed. To ensure that scram time testing is performed within a reasonable time following ~~fuel movement within the reactor pressure vessel or after~~ a shutdown ≥ 120 days or longer, control rods are required to be tested before exceeding 40% RTP. ~~In the event fuel movement is limited to selected core cells, it is the intent of this SR that only those CRDs associated with the core cells affected by the fuel movements are required to be scram time tested.~~ This Frequency is acceptable considering the additional surveillances performed for control rod OPERABILITY, the frequent verification of adequate accumulator pressure, and the required testing of control rods affected by fuel movement within the affected fuel cell and by work on control rods or the CRD System.

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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BASES

SURVEILLANCE REQUIREMENTS (continued)

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, required by footnote (b), are included in the Technical Requirements Manual (Ref. 7) and are established based on a high probability of meeting the acceptance criteria at reactor pressures ≥ 800 psig. The limits for reactor pressures ≥ 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."

Specific examples of work that could affect the scram times are (but are not limited to) the following: removal of any CRD for maintenance or modification; replacement of a control rod; and maintenance or modification of a scram solenoid pilot valve, scram valve, accumulator, isolation valve or check valve in the piping required for scram.

The Frequency of once prior to declaring the affected control rod OPERABLE is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

SR 3.1.4.4

or when fuel movement within the reactor pressure vessel occurs,

When work that could affect the scram insertion time is performed on a control rod or CRD System, testing must be done to demonstrate each affected control rod is still within the limits of Table 3.1.4-1 with the reactor steam dome pressure ≥ 800 psig. Where work has been performed at high reactor pressure, the requirements of SR 3.1.4.3 and SR 3.1.4.4 can be satisfied with one test. However, for a control rod affected by work performed while shutdown, a zero pressure test and a high pressure test may be required. This testing ensures that,

(continued)

When fuel movement within the reactor pressure vessel occurs, only those control rods associated with the core cells affected by the fuel movement are required to be scram time tested. During a routine refueling outage, it is expected that all control rods will be affected.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.4 (continued)

prior to withdrawing the control rod for continued operation, the control rod scram performance is acceptable for operating reactor pressure conditions. Alternatively, a control rod scram test during hydrostatic pressure testing could also satisfy both criteria.

The Frequency of once prior to exceeding 40% RTP is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

This test is also used to demonstrate control rod OPERABILITY when ≥ 40% RTP after work that could affect the scram insertion time is performed on the CRD System.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.

2. FSAR, Paragraph 4.2.3.2.

3. FSAR, Supplement 5A.4.3.

4. FSAR, Section 15.1.

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

6. Letter from R. F. Janecek (BWROG) to R. W. Starostecki (NRC), "BWR Owners' Group Revised Reactivity Control Systems Technical Specifications," BWROG-8754, September 17, 1987.

7. Technical Requirements Manual, Table T5.0-1.

8. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

No change. Included for information only.

BASES

APPLICABLE SAFETY ANALYSES (continued)

amount that is above the pump suction shutoff level in the boron solution storage tank. No credit is taken for the portion of the tank volume that cannot be injected. The SLC system is also used to control suppression pool pH in the event of a DBA LOCA by injecting sodium pentaborate into the reactor vessel. The sodium pentaborate is then transported to the suppression pool and mixed by ECCS flow recirculation through the reactor, out of the break, and into the suppression chamber. The amount of sodium pentaborate solution that must be available for injection following a DBA LOCA is determined as part of the DBA LOCA radiological analysis. This quantity is maintained in the storage tank as specified in the Technical Specifications. The SLC System satisfies Criterion 4 of the NRC Policy Statement (Ref. 3).

LCO

The OPERABILITY of the SLC System provides backup capability for reactivity control independent of normal reactivity control provisions provided by the control rods and provides sufficient buffering agent to maintain the suppression pool pH at or above 7.0 following a DBA LOCA involving fuel damage. The OPERABILITY of the SLC System is based on the conditions of the borated solution in the storage tank and the availability of a flow path to the RPV, including the OPERABILITY of the pumps and valves. Two SLC subsystems are required to be OPERABLE; each contains an OPERABLE pump, an explosive valve, and associated piping, valves, and instruments and controls to ensure an OPERABLE flow path.

APPLICABILITY

In MODES 1 and 2, shutdown capability is required. In MODES 3 and 4, with the mode switch in shutdown, control rod block prevents withdrawal of control rods. This provides adequate controls to ensure that the reactor remains subcritical. In MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Demonstration of adequate SDM [LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"] ensures that the reactor will not become critical. Therefore, the SLC System is not required to be OPERABLE when only a single control rod can be withdrawn.

ACTIONS

A.1

If the sodium pentaborate solution concentration is not within the 10 CFR 50.62 limits (not within Region A of Figure 3.1.7-1 or 3.1.7-2), but greater than original licensing basis limits (within Region B of

(continued)

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BASES

ACTIONS

A.1 (continued)

Figure 3.1.7-1 or 3.1.7-2), the solution must be restored to within Region A limits in 72 hours. It should be noted that the lowest acceptable concentration in Region is 5%. It is not necessary under these conditions to enter Condition C for both SLC subsystems inoperable, since the SLC subsystems are capable of performing their original design basis functions. Because of the low probability of an event and the fact that the SLC System capability still exists for vessel injection under these conditions, the allowed Completion Time of 72 hours is acceptable and provides adequate time to restore concentration to within limits. ~~The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of concentration out of limits or inoperable SLC subsystems during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, an SLC subsystem is inoperable and that subsystem is subsequently returned to OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total duration of 10 days (7 days in Condition B, followed by 3 days in Condition A), since initial failure of the LCO, to restore the SLC System. Then an SLC subsystem could be found inoperable again, and concentration could be restored to within limits. This could continue indefinitely~~.

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock," resulting in establishing the "time zero" at the time the LCO was initially not met instead of at the time Condition A was entered. The 10 day Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~

B.1

If one SLC subsystem is inoperable for reasons other than Condition A, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystem is adequate to perform the shutdown function and provide adequate buffering agent to the suppression pool. However, the overall reliability is reduced because a single failure in the remaining OPERABLE subsystem could result in reduced SLC System capability. The 7 day Completion Time is based on the availability of an OPERABLE subsystem capable of performing the intended SLC System functions and the low probability of a DBA or severe transient occurring requiring SLC injection. ~~The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of concentration out of~~

(continued)

BASES

ACTIONS

~~B.1 (continued)~~

~~limits or inoperable SLC subsystems during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, concentration is out of limits, and is subsequently returned to within limits, the LCO may already have been not met for up to 3 days. This situation could lead to a total duration of 10 days (3 days in Condition A, followed by 7 days in Condition B), since initial failure of the LCO, to restore the SLC System. Then concentration could be found out of limits again, and the SLC subsystem could be restored to OPERABLE. This could continue indefinitely.~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock," resulting in establishing the "time zero" at the time the LCO was initially not met instead of at the time Condition B was entered. The 10 day Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~

C.1

If both SLC subsystems are inoperable for reasons other than Condition A, at least one subsystem must be restored to OPERABLE status within 8 hours. The allowed Completion Time of 8 hours is considered acceptable given the low probability of a DBA or transient occurring requiring SLC injection.

D.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 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 3.1.7.1, SR 3.1.7.2, and SR 3.1.7.3

SR 3.1.7.1 through SR 3.1.7.3 verify 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

(continued)

No change. Included for information only.

BASES

ACTIONS (continued)

I.2

The alternate method to detect and suppress oscillations implemented in accordance with Required Action I.1 was evaluated based on use up to 120 days (Ref. 13). The evaluation, based on engineering judgment, concluded that the likelihood of an instability event that could not be adequately handled by the alternate method during this 120 day period is negligibly small. The 120 day period is intended to be an outside limit to allow for the case where design changes or extensive analysis may be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. This action is not intended to be, and was not evaluated as, a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to normally be accomplished within the Completion Times allowed for Required Actions for Conditions A and B.

SURVILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column of Table 3.3.1.1-1.

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 RPS 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. 9) 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 RPS will trip when necessary.

SR 3.3.1.1.1

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 other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations

(continued)

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BASES

SURVILLANCE REQUIREMENTS

SR 3.3.1.1.1 (continued)

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 limit.

INSERT - BASES SR 3.3.1.1.1

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

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

A restriction to satisfying this SR when < 24% RTP is provided that requires the SR to be met only at ≥ 24% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 24% 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 ≥ 24% RTP, the Surveillance is required to have been satisfactorily performed in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 24% if the Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 24% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

(continued)

INSERT – BASES SR 3.3.1.1.1

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The agreement criteria includes an expectation of one decade of overlap when transitioning between neutron flux instrumentation. The overlap between SRMs and IRMs must be demonstrated prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs. This will ensure that reactor power will not be increased into a neutron flux region without adequate indication. The overlap between IRMs and APRMs is of concern when reducing power into the IRM range (entry into MODE 2 from MODE 1). 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. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above mid-scale on range 1 before SRMs have reached the upscale rod block.

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.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.3

(Not used.)

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM 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.

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

SR 3.3.1.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.6 and SR 3.3.1.1.7

(Not used.)

~~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~~

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.6 and SR 3.3.1.1.7 (continued)

~~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. Overlap between the SRMs and IRMs similarly exists when, prior to withdrawing an SRM from its fully inserted position, its associated IRMs have cleared their downscale rod block Allowable Values, prior to the SRM having reached its upscale rod block Allowable Value. Plant procedures should be consulted to determine the associated detectors.~~

~~As noted, SR 3.3.1.1.7 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.~~

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

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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B 3.3 INSTRUMENTATION

B 3.3.1.2 Source Range Monitor (SRM) Instrumentation

BASES

BACKGROUND

The SRMs provide the operator with information relative to the neutron flux level at very low flux levels in the core. As such, the SRM indication is used by the operator to monitor the approach to criticality and determine when criticality is achieved. The SRMs are maintained fully inserted until the count rate is greater than a minimum allowed count rate (a control rod block is set at this condition). After SRM to intermediate range monitor (IRM) overlap is demonstrated (as required by ~~SR 3.3.1.1.6~~ SR 3.3.1.1.1), the SRMs are normally fully withdrawn from the core.

The SRM subsystem of the Neutron Monitoring System (NMS) consists of four channels. Each of the SRM channels can be bypassed, but only one at any given time, by the operation of a bypass switch. Each channel includes one detector that can be physically positioned in the core. Each detector assembly consists of a miniature fission chamber with associated cabling, signal conditioning equipment, and electronics associated with the various SRM functions. The signal conditioning equipment converts the current pulses from the fission chamber to analog DC currents that correspond to the count rate. Each channel also includes indication, alarm, and control rod blocks. However, this LCO specifies OPERABILITY requirements only for the monitoring and indication functions of the SRMs.

During refueling, shutdown, and low power operations, the primary indication of neutron flux levels is provided by the SRMs or special movable detectors connected to the normal SRM circuits. The SRMs provide monitoring of reactivity changes during fuel or control rod movement and give the control room operator early indication of subcritical multiplication that could be indicative of an approach to criticality.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling and low power operation is provided by LCO 3.9.1, "Refueling Equipment Interlocks"; LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"; LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"; IRM Neutron Flux - High and Average Power Range Monitor (APRM) Neutron Flux - High(Setdown) Functions; and LCO 3.3.2.1, "Control Rod Block Instrumentation."

(continued)

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BASES

LCO (continued)

indication can be generated. These special detectors provide more flexibility in monitoring reactivity changes during fuel loading, since they can be positioned anywhere within the core during refueling. They must still meet the location requirements of SR 3.3.1.2.2 and all other required SRs for SRMs.

For an SRM channel to be considered OPERABLE, it must be providing neutron flux monitoring indication.

APPLICABILITY

The SRMs are required to be OPERABLE in MODES 2, 3, 4, and 5 prior to the IRMs being on scale on Range 3 to provide for neutron monitoring. In MODE 1, the APRMs provide adequate monitoring of reactivity changes in the core; therefore, the SRMs are not required. In MODE 2, with IRMs on Range 3 or above, the IRMs provide adequate monitoring and the SRMs are not required.

ACTIONS

A.1 and B.1

In MODE 2, with the IRMs on Range 2 or below, SRMs provide the means of monitoring core reactivity and criticality. With any number of the required SRMs inoperable, the ability to monitor neutron flux is degraded. Therefore, a limited time is allowed to restore the inoperable channels to OPERABLE status.

Provided at least one SRM remains OPERABLE, Required Action A.1 allows 4 hours to restore the required SRMs to OPERABLE status. This time is reasonable because there is adequate capability remaining to monitor the core, there is limited risk of an event during this time, and there is sufficient time to take corrective actions to restore the required SRMs to OPERABLE status or to establish alternate IRM monitoring capability. During this time, control rod withdrawal and power increase is not precluded by this Required Action. Having the ability to monitor the core with at least one SRM, proceeding to IRM Range 3 or greater (with overlap ~~required~~ by ~~SR 3.3.1.1.6~~), and thereby exiting the Applicability of this LCO, is acceptable for ensuring adequate core monitoring and allowing continued operation.

verified

SR 3.3.1.1.1

With three required SRMs inoperable, Required Action B.1 allows no positive changes in reactivity (control rod withdrawal must be immediately suspended) due to inability to monitor the changes. Required Action A.1 still applies and allows 4 hours to restore

(continued)

No change. Included for information only.

BASES

ACTIONS

A.1 and B.1 (continued)

monitoring capability prior to requiring control rod insertion. This allowance is based on the limited risk of an event during this time, provided that no control rod withdrawals are allowed, and the desire to concentrate efforts on repair, rather than to immediately shut down, with no SRMs OPERABLE.

C.1

In MODE 2, if the required number of SRMs is not restored to OPERABLE status within the allowed Completion Time, the reactor shall be placed in MODE 3. With all control rods fully inserted, the core is in its least reactive state with the most margin to criticality. 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.

D.1 and D.2

With one or more required SRMs inoperable in MODE 3 or 4, the neutron flux monitoring capability is degraded or nonexistent. The requirement to fully insert all insertable control rods ensures that the reactor will be at its minimum reactivity level while no neutron monitoring capability is available. Placing the reactor mode switch in the shutdown position prevents subsequent control rod withdrawal by maintaining a control rod block. The allowed Completion Time of 1 hour is sufficient to accomplish the Required Action, and takes into account the low probability of an event requiring the SRM occurring during this interval.

E.1 and E.2

With one or more required SRMs inoperable in MODE 5, the ability to detect local reactivity changes in the core during refueling is degraded. CORE ALTERATIONS must be immediately suspended and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Suspending CORE ALTERATIONS prevents the two most probable causes of reactivity changes, fuel loading and control rod withdrawal, from occurring. Inserting all insertable control rods ensures that the reactor will be at its minimum reactivity given that fuel is present in the

(continued)

Penetration Flow Path

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BASES

LCO
(continued)

6. Primary Containment Isolation Valve (PCIV) Position

PCIV position is provided for verification of containment integrity. In the case of PCIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active PCIV in a containment penetration flow path, i.e., two total channels of PCIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE. The indication for each PCIV consists of green and red indicator lights that illuminate to indicate whether the PCIV is fully open, fully closed, or in a mid-position. Therefore, the PAM specification deals specifically with this portion of the instrumentation channel.

Each penetration is treated separately and each penetration flow path is considered a separate function. Therefore, separate Condition entry is allowed for each inoperable penetration flow path.

7., 8. (Deleted)

9. Suppression Pool Water Temperature

Suppression pool water temperature is a Type A variable provided to detect a condition that could potentially lead to containment breach and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature

(continued)

LCO

9. Suppression Pool Water Tempterature (continued)

instrumentation allows operators to detect trends in suppression pool water temperature in sufficient time to take action to prevent steam quenching vibrations in the suppression pool. Fifteen active RTD elements are used for RG 1.97 compliance. Eleven of these devices are grouped together to provide an average measure of the upper region of the suppression pool. These input to a single recorder. The other four RTDs are used to measure the lower region of the suppression pool and are spaced almost equilaterally. They input to two recorders. However, to ensure the average temperature of the suppression pool is monitored, only two of these RTDs per quadrant are needed, since other means are available to ensure the average bulk suppression pool temperature is known if a few of the RTDs are inoperable. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channels.

Each suppression pool quadrant is treated separately and temperature indication in each suppression pool quadrant is considered a separate function. Therefore, separate Condition entry is allowed for each suppression pool quadrant with inoperable water temperature indication.

10. Drywell Temperature in the Vicinity of Reactor Vessel Level Instrument Reference Leg

Drywell temperature in the vicinity of reactor vessel level instrument reference legs is a Type A variable provided to measure drywell temperature so that proper compensation of reactor water level instruments can be accomplished. The drywell temperature is measured by six RTDs in the vicinity of the associated reference legs with the output being recorded on recorders in the control room. This is the primary indication used by the operator during an accident. Therefore, the PAM specification deals specifically with this portion of the instrumentation channel.

11. Diesel Generator Parameters

Diesel generator (DG) parameters are Type A variables provided to allow the operator to ensure proper operation of the DGs and to control the DGs post accident. Each of the four parameters (output voltage, output current, output power, and battery voltage) is monitored for each of the two unit specific DGs and the swing DG and is read on indicators in the control room. These are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channels.

(continued)

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BASES

BACKGROUND (continued)

5. Reactor Water Cleanup System Isolation

The Reactor Vessel Water Level - Low Low, Level 2 Isolation Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into two two-out-of-two trip systems. The Area Temperature - High Function receives input from six temperature monitors, three to each trip system. The Area Ventilation Differential Temperature - High Function receives input from six differential temperature monitors, three in each trip system. These are configured so that any one input will trip the associated trip system. Each of the two trip systems is connected to one of the two valves on the RWCU penetration. However, the SLC System Initiation Function only provides an input to one trip system, thus closes only one valve.

RWCU Functions isolate the Group 5 valves.

6. RHR Shutdown Cooling System Isolation

The Reactor Vessel Water Level - Low, Level 3 Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected to two-out-of-two trip systems.

The Reactor Vessel Pressure - High Function receives input from two channels, with each channel in one trip system using a one-out-of-one logic. Each of the two trip systems is connected to one of the two valves on the shutdown cooling penetration.

RHR Shutdown Cooling System Isolation Functions isolate the Group 6 valves. The outboard shutdown cooling isolation valve, 2E11-F009, while not a PCIV, isolates on the same signals which isolate Group 6 valves.

INSERT - Bases 3.3.6.1 Background

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the primary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves to limit offsite doses. Refer to LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Applicable Safety Analyses Bases for more detail of the safety analyses.

Primary containment isolation instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 7). Certain instrumentation Functions

(continued)

INSERT 1 – Bases 3.3.6.1 Background

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7. Traversing Incore Probe (TIP) System Isolation

The Reactor Vessel Water Level – Low, Level 3 Isolation Function receives input from two reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into one two-out-of-two logic trip system. The Drywell Pressure – High Isolation function receives input from two drywell pressure channels. The outputs from the drywell pressure channels are connected into one two-out-of-two logic trip system.

When either isolation Function actuates, the TIP drive mechanisms will withdraw the TIPs, if inserted, and close the inboard TIP system isolation ball valves when the TIPs are fully withdrawn. The outboard TIP system isolation valves are manual shear valves.

TIP System Isolation Functions isolate the Group 13 valves (inboard isolation ball valves).

No change. Included for information only.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.d. Reactor Vessel Water Level - Low Low, Level 2 (continued)

The Reactor Vessel Water Level - Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level - Low Low, Level 2 Allowable Value (LCO 3.3.5.1), since the capability to cool the fuel may be threatened.

This Function isolates the Group 5 valves.

6. RHR Shutdown Cooling System Isolation

6.a. Reactor Steam Dome Pressure - High

The Reactor Steam Dome Pressure - High Function is provided to isolate the shutdown cooling portion of the Residual Heat Removal (RHR) System. This interlock is provided only for equipment protection to prevent an intersystem LOCA scenario, and credit for the interlock is not assumed in the accident or transient analysis in the FSAR.

The Reactor Steam Dome Pressure - High signals are initiated from two transmitters that are connected to different taps on the RPV. Two channels of Reactor Steam Dome Pressure - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Function is only required to be OPERABLE in MODES 1, 2, and 3, since these are the only MODES in which the reactor can be pressurized; thus, equipment protection is needed. The Allowable Value was chosen to be low enough to protect the system equipment from overpressurization.

This Function isolates the Group 6 valves (and 2E11-F009).

6.b. Reactor Vessel Water Level - Low, Level 3

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level - Low, Level 3 Function associated with RHR Shutdown Cooling System isolation is not directly assumed in safety analyses because a break of the RHR Shutdown Cooling

(continued)

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6.b. Reactor Vessel Water Level - Low, Level 3 (continued)

System is bounded by breaks of the recirculation and MSL. The RHR Shutdown Cooling System isolation on Level 3 supports actions to ensure that the RPV water level does not drop below the top of the active fuel during a vessel draindown event caused by a leak (e.g., pipe break or inadvertent valve opening) in the RHR Shutdown Cooling System. The top of active fuel is defined in "Applicable Safety Analyses" for Safety Limit 2.1.1.3, "Reactor Vessel Water Level," found in the Bases for Safety Limit 2.1.1, "Reactor Core SLs."

Reactor Vessel Water Level - Low, Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of the Reactor Vessel Water Level - Low, Level 3 Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (d) to Table 3.3.6.1-1), only two channels of the Reactor Vessel Water Level - Low, Level 3 Function are required to be OPERABLE in MODES 4 and 5 (and must input into the same trip system), provided the RHR Shutdown Cooling System integrity is maintained. System integrity is maintained provided the piping is intact and no maintenance is being performed that has the potential for draining the reactor vessel through the system.

The Reactor Vessel Water Level - Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level - Low, Level 3 Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level - Low, Level 3 Function is only required to be OPERABLE in MODES 3, 4, and 5 to prevent this potential flow path from lowering the reactor vessel level to the top of the fuel. In MODES 1 and 2, another isolation (i.e., Reactor Steam Dome Pressure - High) and administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

This Function isolates the Group 6 valves (and 2E11-F009).

INSERT - Bases 3.3.6.1 ASA

Note 2

ACTIONS

~~A Note~~ has been provided to modify the ACTIONS related to primary containment isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered,

INSERT - Bases 3.3.6.1 Actions

(continued)

Traversing Incore Probe System Isolation

7.a. Reactor Vessel Water Level — Low, Level 3

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 3 supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Reactor Vessel Water Level — Low, Level 3 Function associated with isolation is implicitly assumed in the FSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level — Low, Level 3 signals are initiated from level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Two channels of Reactor Vessel Water Level — Low, Level 3 Function are available and are required to be OPERABLE to ensure that no single instrument failure can initiate an inadvertent isolation actuation. The isolation function is ensured by the manual shear valve in each penetration.

The Reactor Vessel Water Level — Low, Level 3 Allowable Value was chosen to be the same as the RPS Level 3 scram Allowable Value (LCO 3.3.1.1), since isolation of these valves is not critical to orderly plant shutdown.

This Function isolates the Group 13 valves.

7.b. Drywell Pressure — High

High drywell pressure can indicate a break in the RCPB inside the primary containment. The isolation of some of the primary containment isolation valves on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 100 are not exceeded. The Drywell Pressure — High Function, associated with isolation of the primary containment, is implicitly assumed in the FSAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Two channels of Drywell Pressure — High per Function are available and are required to be OPERABLE to ensure that no single instrument failure can initiate an inadvertent actuation. The isolation function is ensured by the manual shear valve in each penetration.

The Allowable Value was selected to be the same as the ECCS Drywell Pressure — High Allowable Value (LCO 3.3.5.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 13 valves.

INSERT – Bases 3.3.6.1 Actions

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The ACTIONS are modified by two Notes. Note 1 allows penetration flow path(s) to be unisolated intermittently under administrative controls. 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 primary containment isolation is indicated.

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

36 hours (Required Actions D.2.1 and D.2.2). The 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.

E.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 2 within 6 hours.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

F.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels.

For the RWCU Area and Area Ventilation Differential Temperature - High Functions, the affected penetration flow path(s) may be considered isolated by isolating only that portion of the system in the associated room monitored by the inoperable channel. That is, if the RWCU pump room A area channel is inoperable, the pump room A area can be isolated while allowing continued RWCU operation utilizing the B RWCU pump.

Alternately, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition ~~G~~ H must be entered and its Required Actions taken.

The 1 hour Completion Time is acceptable because it minimizes risk while allowing sufficient time for personnel to isolate the affected penetration flow path(s).

(continued)

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BASES

INSERT - BASES 3.3.6.1 Condition G

ACTIONS (continued)

~~G.1 and G.2~~ H.1 and H.2

or G

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, or any Required Action of Condition ~~F~~ is not met and the associated Completion Time has expired, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

~~H.1 and H.2~~ I.1 and I.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the SLC System is declared inoperable or the RWCU System is isolated. Since this Function is required to ensure that the SLC System performs its intended function, sufficient remedial measures are provided by declaring the SLC System inoperable or isolating the RWCU System.

The 1 hour Completion Time is acceptable because it minimizes risk while allowing sufficient time for personnel to isolate the RWCU System.

~~I.1 and I.2~~ J.1 and J.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated penetration flow path should be closed. However, if the shutdown cooling function is needed to provide core cooling, these Required Actions allow the penetration flow path to remain unisolated provided action is immediately initiated to restore the channel to OPERABLE status or to isolate the RHR Shutdown Cooling System (i.e., provide alternate decay heat removal capabilities so 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.

(continued)

INSERT – Bases 3.3.6.1 Condition G

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G.1 and G.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels. The 24 hour Completion Time is acceptable due to the fact that the TIP System penetration is a small bore (approximately ½ inch), its isolation in a design basis event (with loss of offsite power) would be via the manually operated shear valves, and the ability to manually isolate by either the normal isolation valve or the shear valve is unaffected by the inoperable instrumentation. Alternately, if it is not desired to isolate the affected penetration flow path(s), Condition H must be entered and its Required Actions taken.

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BASES

LCO (continued)

subsystems and ADS must therefore be OPERABLE to satisfy the single failure criterion required by Reference 11. (Reference 10 takes no credit for HPCI.) HPCI must be OPERABLE due to risk consideration.

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR low pressure permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3, when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, when reactor steam dome pressure is ≤ 150 psig, ADS and HPCI are not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS - Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of LCO 3.0.4.b, which allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

or if one LPCI pump in both LPCI subsystems is inoperable,

subsystem(s)

If any one low pressure ECCS injection/spray subsystem is inoperable, the inoperable ~~subsystem~~ must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is

(continued)

No change. Included for information only.

BASES

ACTIONS

A.1 (continued)

based on a reliability study (Ref. 12) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

B.1 and B.2

If the inoperable low pressure ECCS subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to 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.

C.1 and C.2

If the HPCI System is inoperable and the RCIC System is verified to be OPERABLE, the HPCI System must be restored to OPERABLE status within 14 days. In this condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY within 1 hour is therefore required when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be verified, however, Condition E must be immediately entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

(continued)

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BASES (continued)

ACTIONS

D.1 and D.2

, or one LPCI pump in both LPCI subsystems,

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to an inoperable HPCI System, the inoperable low pressure ECCS injection/spray subsystem or the HPCI System must be restored to OPERABLE status within 72 hours. In this condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is significantly reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since both a high pressure system (HPCI) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the HPCI System or the low pressure ECCS injection/spray subsystem to OPERABLE status. This Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

E.1 and E.2

With one ADS valve inoperable, no action is required, because an analysis demonstrated that the remaining six ADS valves are capable of providing the ADS function, per Reference 16.

If any Required Action and associated Completion Time of Condition C or D 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. Entry into MODE 3 is not required if the reduction in reactor steam dome pressure to ≤ 150 psig results in exiting the Applicability for the Condition, and the ≤ 150 psig is achieved within the given 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

When multiple ECCS subsystems are inoperable, as stated in Condition ~~H~~ F, the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

No change. Included for information only.

BASES

ACTIONS (continued)

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable except for inoperability due to leakage not within a limit specified in an SR to this LCO, the affected penetration flow paths must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured.

For a penetration isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available valve to the primary containment. The device must be subjected to leakage testing requirements equivalent to the inoperable valve. For example: 1) if the inoperable valve is required to be Type C tested per 10 CFR 50, Appendix J, Option B (Ref. 5), the device chosen to isolate the penetration must also be subjected to Appendix J, Option B, Type C testing; and 2) if the inoperable valve is not subjected to Appendix J, Option B, testing ("-" in Reference 2, Table T7.0-1, Test Type column), the isolation device does not have to be subjected to Appendix J, Option B, testing.

If a valve is inoperable due to isolation time not within limits or other condition that would not be expected to adversely affect leakage characteristics, the inoperable valve may be used to isolate the penetration.

The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside containment

(continued)

ACTIONS

A.1 and A.2 (continued)

and capable of potentially being mispositioned are in the correct position. The Completion Time of "Once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "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" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

two notes. Note 1

Required Action A.2 is modified by ~~a Note that~~ applies to isolation devices located in high radiation areas, and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

INSERT - BASES 3.6.1.3 Action A

B.1

With one or more penetration flow paths with two PCIVs inoperable except due to leakage not within limits, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. The device must be subjected to leakage testing requirements equivalent to the inoperable valve. For example: 1) if the inoperable valve is required to be Type C tested per 10 CFR 50, Appendix J, Option B, the device chosen to isolate the penetration must also be subjected to Appendix J, Option B, Type C testing; and 2) if the inoperable valve is not subjected to Appendix J, Option B, testing ("-" in Reference 2, Table T7.0-1, Test Type column), the isolation device does not have to be subjected to Appendix J, Option B, testing.

(continued)

INSERT – BASES 3.6.1.3 Action A

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Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

No change. Included for information only.

BASES

ACTIONS

B.1 (continued)

If a valve is inoperable due to isolation time not within limits or other condition that would not be expected to adversely affect leakage characteristics, the inoperable valve may be used to isolate the penetration. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

C.1 and C.2

With one or more penetration flow paths with one PCIV inoperable, except due to leakage not within limits, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. The device must be subjected to leakage testing requirements equivalent to the inoperable valve, except for inoperable valves in the Core Spray and Low Pressure Coolant Injection (LPCI) systems. For example: 1) if the inoperable valve is required to be Type C tested per 10 CFR 50, Appendix J, Option B, the device chosen to isolate the penetration must also be subjected to Appendix J, Option B, Type C testing; and 2) if the inoperable valve is not subjected to Appendix J, Option B, testing ("-" in Reference 2, Table T7.0-1, Test Type column), the isolation device does not have to be subjected to Appendix J, Option B, testing. For Core Spray and LPCI system valve inoperability, the device chosen to isolate the affected penetration is not required to be tested per 10 CFR 50, Appendix J, Option B, leakage testing. This exception is based on the integrity of the system piping, which serves to minimize leakage into the secondary containment.

If a valve is inoperable due to isolation time not within limits or other condition that would not be expected to adversely affect leakage characteristics, the inoperable valve may be used to isolate the penetration.

(continued)

BASES

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ACTIONS

The Completion Time of 4 hours for PCIVs other than those in penetrations with a closed system and EFCVs is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY in MODES 1, 2, and 3.

The closed system must meet the requirements of Reference 8.

C.1 and C.2 (continued)

~~Required Action C.1 must be completed within 4 hours for lines other than excess flow check valve (EFCV) lines and 12 hours for EFCV lines.~~ The Completion Time of 4 hours is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The Completion Time of 12 hours is reasonable considering the instrument to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated.

for penetrations with a closed system

72

also

for EFCVs

72

The Completion Time of once per 31 days for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions.

Required Action C.2 is modified by ~~a Note that~~ applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

two notes. Note 1

INSERT - BASES 3.6.1.3 Action C

D.1

With the secondary containment bypass leakage rate or MSIV leakage rate not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 4 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage

(continued)

INSERT – BASES 3.6.1.3 Action C

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Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1 (continued)

stating that the SR is not required to be met when the 18 inch purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.3.2

and not locked, sealed, or otherwise secured

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment 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 require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside primary containment, and capable of being mispositioned, are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

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 isolation devices, once they have been verified to be in the proper position, is low. A second Note has been included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open.

SR 3.6.1.3.3

This SR verifies that each primary containment manual isolation valve and blind flange that is located inside primary containment and is

and not locked, sealed, or otherwise secured

(continued)

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BASES

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SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.3 (continued)

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. For these isolation devices inside primary containment, the Frequency defined as "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" is appropriate since these isolation devices are operated under administrative controls and the probability of their misalignment is low.

This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

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 the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA and personnel safety reasons. Therefore, the probability of misalignment of these isolation devices, once they have been verified to be in their proper position, is low. A second Note has been included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open.

SR 3.6.1.3.4

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Actuation and monitoring circuitry is provided in the main control room. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. The circuitry is such that a light illuminates upon loss of explosive charge continuity. Ensuring that the light illuminates when voltage is applied and that it is extinguished when installed in the circuit provides assurance of explosive valve continuity. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.3.5

Verifying the isolation time of each power operated ~~and each~~ automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full

(continued)

No change. Included for information only.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.5 (continued)

closure isolation time is demonstrated by SR 3.6.1.3.6. The isolation time test ensures that each valve will isolate in a time period less than or equal to that listed in the FSAR and that no degradation affecting valve closure since the performance of the last surveillance has occurred. (EFCVs are not required to be tested because they have no specified time limit). The Frequency of this SR is 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 analyses. This ensures that the calculated radiological consequences of these events remain within 10 CFR 50.67 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 SR 3.3.6.1.6 overlaps this SR to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.3.8

This SR requires a demonstration that each reactor instrumentation line excess flow check valve (EFCV) (of a representative sample) is OPERABLE by verifying that the valve reduces flow to within limits on an actual or simulated instrument line break condition. (The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested at least once every 10 years [nominal]. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes, and operating environments. This ensures that any potentially common problem

(continued)

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BASES (continued)

REFERENCES

1. FSAR, Chapter 15.

2. Technical Requirements Manual, Table T7.0-1.

3. FSAR, Subsection 15.1.39.

4. FSAR, Section 6.2.

5. 10 CFR 50, Appendix J, Option B.

6. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

7. Primary Containment Leakage Rate Testing Program.

8. FSAR, Section 3.1

TSTF-458-T

BASES

ACTIONS (continued)

C.1

Suppression pool average temperature is allowed to be > 100°F when any OPERABLE IRM channel is > 25/40 divisions of full scale on Range 7, and when testing that adds heat to the suppression pool is being performed. However, if temperature is > 105°F, all testing must be immediately suspended to preserve the heat absorption capability of the suppression pool. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1, D.2, and D.3

Suppression pool average temperature > 110°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further, cooldown to MODE 4 is required at normal cooldown rates (provided pool temperature remains ≤ 120°F). Additionally, when suppression pool temperature is > 110°F, increased monitoring of pool temperature is required ~~to ensure that it remains ≤ 120°F~~. The once per 30 minute Completion Time is adequate, based on operating 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.

Additionally, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 4 within 36 hours.

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~~ Time is 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 and local temperatures could be exceeded very quickly.

(continued)

TSTF-322

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1 and SR 3.6.4.1.2

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 3.6.4.1.1 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. An access opening contains one inner and one outer door. The intent is not to breach the secondary containment at any time when secondary containment is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times. However, all secondary containment access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being performed on an access opening. When the secondary containment configuration excludes Zone I and/or Zone II, these SRs also include verifying the hatches and doors separating the common refueling floor zone from the reactor building(s). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

INSERT - BASES 3.6.4.1 SR

SR 3.6.4.1.3 and SR 3.6.4.1.4

~~The Unit 1 and Unit 2 SGT Systems exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. To ensure that all fission products are treated, SR 3.6.4.1.3 verifies that the appropriate SGT System(s) will rapidly establish and maintain a negative pressure in the secondary containment. This is confirmed by demonstrating that the required SGT subsystem(s) will draw down the secondary containment to ≥ 0.20 inch of vacuum water gauge in ≤ 120 seconds (13 seconds of diesel generator startup and breaker closing time is included in the 120 second drawdown time). This cannot be accomplished if the secondary containment boundary is not intact. SR 3.6.4.1.4 demonstrates that the required SGT subsystem(s) can~~

(continued)

INSERT – Bases 3.6.4.1 SR

TSTF-322

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. The SGT System is designed to draw down pressure in the secondary containment to ≥ 0.20 inches of vacuum water gauge in ≤ 120 seconds and maintain pressure in the secondary containment at ≥ 0.20 inches of vacuum water gauge for 1 hour at a flow rate ≤ 4000 CFM. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.3 and SR 3.6.4.1.4 verify that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can rapidly be established and maintained. When the SGT System is operating as designed, the establishment and maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. Establishment of this pressure is confirmed by SR 3.6.4.1.3, which demonstrates that the secondary containment can be drawn down to ≥ 0.20 inches of vacuum water gauge in ≤ 120 seconds using the required SGT subsystem(s). SR 3.6.4.1.4 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.20 inches of vacuum water gauge for 1 hour using the required SGT subsystem(s) at a flow rate ≤ 4000 CFM. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. The primary purpose of these SRs is to ensure secondary containment boundary integrity. The secondary purpose of these SRs is to ensure that the SGT subsystem(s) being tested function as designed. There is a separate LCO with Surveillance Requirements which serves the primary purpose of ensuring OPERABILITY of the SGT System. These SRs need not be performed with each SGT subsystem. The SGT subsystem(s) used for these Surveillances are staggered to ensure that in addition to the requirements of LCO 3.6.4.3, the required SGT subsystem(s) will perform this test. The inoperability of the SGT System does not necessarily constitute a failure of these Surveillances relative to the secondary containment OPERABILITY.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.3 and SR 3.6.4.1.4 (continued)

~~maintain ≥ 0.20 inch of vacuum water gauge for 1 hour at a flow rate ≤ 4000 cfm for each SGT subsystem. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. Therefore, these two tests are used to ensure secondary containment boundary integrity. Since these SRs are secondary containment tests, they 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, each SGT subsystem or combination of subsystems will perform this test.~~ The number of SGT subsystems and the required combinations are dependent on the configuration of the secondary containment and are detailed in the Technical Requirements Manual (Ref. 3). The Note to SR 3.6.4.1.3 and SR 3.6.4.1.4 specifies that the number of required SGT subsystems be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 15.1.39.

2. FSAR, Section 15.1.41.

3. Technical Requirements Manual, Section 8.0.

4. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

containment so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The power operated, automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 3.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed, or open in accordance with appropriate administrative controls, automatic SCIVs are de-activated and secured in their closed position, and blind flanges are in place. These passive isolation valves or devices are listed in Reference 3.

The SCIVs required to be OPERABLE are dependent on the configuration of the secondary containment (which is dependent on the operating status of both units, as well as the configuration of doors, hatches, refueling floor plugs, and available flow paths to SGT Systems). The required boundary encompasses the zones which can be postulated to contain fission products from accidents required to be considered for the condition of each unit, and furthermore, must include zones not isolated from the SGT subsystems being credited for meeting LCO 3.6.4.3, "Standby Gas Treatment (SGT) System." The required SCIVs are those in penetrations communicating with the zones required for secondary containment OPERABILITY and are detailed in Reference 3.

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, the OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in

(continued)

No change. Included for information only.

BASES

APPLICABILITY (continued)

MODE 4 or 5, except for other situations under which significant radioactive releases can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment. (Note: Moving irradiated fuel assemblies in the secondary containment may also occur in MODES 1, 2, and 3.)

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated 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 isolation is indicated.

The second Note provides clarification that for the purpose of this LCO separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment. The Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to

(continued)

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BASES

ACTIONS

A.1 and A.2 (continued)

isolate the penetration, and the probability of a DBA, which requires the SCIVs to close, occurring during this short time is very low.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time of once per 31 days is appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

two notes. Note 1

Required Action A.2 is modified by ~~a Note that~~ applies to devices located in high radiation areas and allows them to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment once they have been verified to be in the proper position, is low.

INSERT - BASES 3.6.4.2 Action A

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable considering the time required to isolate the penetration and the probability of a DBA, which requires the SCIVs to close, occurring during this short time, is very low.

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 to MODE 4 within 36 hours. The allowed Completion Times are

(continued)

INSERT – BASES 3.6.4.2 Action A

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Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

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BASES

ACTIONS

C.1, and C.2 (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.

D.1, D.2, and D.3

If any Required Action and associated Completion Time of Condition A or B are not met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and the movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action D.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving fuel while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations.

Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

not locked, sealed, or otherwise secured and is

This SR verifies that each secondary containment manual isolation valve and blind flange that 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 isolation devices in secondary containment that are capable of being mispositioned are in the correct position.

This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

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

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1 (continued)

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.

SR 3.6.4.2.2

Verifying that the isolation time of each power operated ~~and each~~ 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent 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 SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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BASES

ACTIONS

A.2 (continued)

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one required offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

~~The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a, b, or c. If Condition A is entered while, for instance, the swing DG is inoperable, and that DG is subsequently returned OPERABLE, LCO 3.8.1.a, b, or c may already have been not met for up to 14 days. This situation could lead to a total of 17 days, since initial failure to meet LCO 3.8.1.a, b, and c, to restore the offsite circuit. At this time, the swing DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 31 days) allowed prior to complete restoration of LCO 3.8.1.a, b, and c. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a, b, or c. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hours and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.~~

(continued)

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BASES

ACTIONS

~~A.3 (continued)~~

~~As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time LCO 3.8.1.a, b, or c was initially not met, instead of at the time that Condition A was entered.~~

B.1

To ensure a highly reliable power source remains with one Unit 2 or the swing DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a Unit 2 or swing DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable Unit 2 or swing DG exists; and

b. A redundant required feature on the other division (Division 1 or 2), or divisions in the case of the Unit 1 and 2 Standby Gas Treatment (SGT) System, is inoperable.

If, at any time during the existence of this Condition (one Unit 2 or swing DG inoperable), a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

(continued)

No change. Included for information only.

BASES

ACTIONS (continued)

B.4

Regulatory Guide 1.93 (Ref. 6), provides guidance that operation in Condition B may continue for 72 hours. A risk-informed, deterministic evaluation performed for Plant Hatch justifies operation in Condition B for 14 days, provided action is taken to ensure two DGs are dedicated to each Hatch unit. This is accomplished for an inoperable A or C DG by inhibiting the automatic alignment (on a LOCA or LOSP signal) of the swing DG to the other unit. If the inoperable DG is the swing DG, each unit has two dedicated DGs. For an inoperable swing DG, a 72 hour Completion Time applies unless the restrictions specified following this paragraph are satisfied. In Condition B for each defined Completion Time and restriction (if applicable), the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Unit 2 Class 1E Distribution System. The Completion Times take into account the capacity and capability of the remaining AC sources, reasonable time for maintenance, and low probability of a DBA occurring during this period. The 14 day Completion Time is also subject to additional restrictions for planned maintenance on other plant systems; these are controlled by 90AC-OAM-002-0. Use of the 14 day Completion time is permitted as follows:

- For the Unit 2 DGs:

  Once per DG per operating cycle for performing major overhaul of a DG.

  As needed to complete unplanned maintenance. This time shall be minimized.

- For the swing DG:

  The additional restrictions apply prior to using a Completion Time of greater than 72 hours.

  The 14 day Completion Time may be used once per Unit 1 operating cycle for performing a major overhaul of the swing DG.

  The time may be used as needed to complete unplanned maintenance. This time shall be minimized.

- As needed for the swing DG when it is inhibited from automatically aligning to Unit 2 in order for the 14 day Completion Time to be used for a Unit 1 DG.

(continued)

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BASES

ACTIONS

B.4 (continued)

The "AND" connector between the 72 hour and 14 day Completion Times means that both Completion Times apply simultaneously. That is, the 14 day Completion Time for an A or C DG with the swing DG inhibited applies from the time of entry into Condition B, not from the time the swing DG is inhibited.

~~The fourth Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a, b, or c. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, LCO 3.8.1.a, b, or c may already have been not met for up to 72 hours. This situation could lead to a total of 17 days, since initial failure to meet LCO 3.8.1.a, b, and c, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of LCO 3.8.1.a, b, and c. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a, b, or c. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connectors between the Completion Times mean that all Completion Times apply simultaneously, and the more restrictive must be met.~~

~~As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time that LCO 3.8.1.a, b, or c was initially not met, instead of the time that Condition B was entered.~~

C.1

To ensure a highly reliable power source remains with one required Unit 1 DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

(continued)

No change. Included for information only.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.5 (continued)

To minimize the wear on moving parts that do not get lubricated when the engine is not running, this SR has been modified by a Note (Note 1) to indicate that all DG starts for this Surveillance may be preceded by an engine prelube period and followed by a warmup prior to loading.

Note 2 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 3 modifies this Surveillance by stating that momentary load transients because of changing bus loads do not invalidate this test.

Note 4 indicates that this Surveillance is required to 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.

To minimize testing of the swing DG, Note 5 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units, with the DG started using the starting circuitry of one unit and synchronized to the ESF bus of that unit for one periodic test and started using the starting circuitry of the other unit and synchronized to the ESF bus of that unit during the next periodic test. This is allowed since the main purpose of the Surveillance, to ensure DG OPERABILITY, is still being verified on the proper frequency, and each unit's starting circuitry and breaker control circuitry, which is only being tested every second test (due to the staggering of the tests), historically have a very low failure rate. If the swing DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.6

Transfer of each 4.16 kV ESF 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

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. Credit may be taken for unplanned events that satisfy this SR.

INSERT 1 - BASES 3.8.1

normally

This Surveillance tests the applicable logic associated with the Unit 2 swing bus. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with the Unit 1 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1 or 2 does not have applicability to Unit 1. As the Surveillance represents separate tests, the Unit 2 Surveillance should not be performed with Unit 2 in MODE 1 or 2 and the Unit 1 test should not be performed with Unit 1 in MODE 1 or 2.

normally

normally

SR 3.8.1.7

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The largest single load for each DG is a residual heat removal service water pump at rated flow (1225 bhp). This Surveillance may be accomplished by: a) tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power or while solely supplying the bus, or b) tripping its associated single largest post-accident load with the DG solely supplying the bus. Although Plant Hatch Unit 2 is not committed to IEEE-387-1984, (Ref. 11), this SR is consistent with the IEEE-387-1984 requirement that states the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower. For all DGs, this represents 65.5 Hz,

(continued)

Insert 1 - Bases 3.8.1

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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

equivalent to 75% of the difference between nominal speed and the overspeed trip setpoint.

The voltage and frequency specified are consistent with the nominal range for the DG. SR 3.8.1.7.a corresponds to the maximum frequency excursion, while SR 3.8.1.7.b is the voltage to which the DG must recover following load rejection. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for Note 1 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. Credit may be taken for unplanned events that satisfy this SR.

INSERT 1 - BASES 3.8.1

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing is performed with only the DG providing power to the associated 4160 V ESF bus. The DG is not synchronized with offsite power.

To minimize testing of the swing DG, Note 2 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit (no unit specific DG components are being tested). If the swing DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.8

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.88. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

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

This SR is modified by three Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Note 2 is provided in recognition that if the offsite electrical power distribution system is lightly loaded (i.e., system voltage is high, it may not be possible to raise voltage without creating an overvoltage condition on the ESF bus. Therefore, to ensure the bus voltage, supplied ESF loads, and DG are not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage or ESF bus loading does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable.

INSERT 1 - BASES 3.8.1

To minimize testing of the swing DG, Note 3 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit (no unit specific DG components are being tested). If the swing DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

(continued)

No change. Included for information only.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

This Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source and is consistent with Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1). This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start time of 12 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, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these 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. For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations.

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. The reason for Note 2 is that performing the Surveillance would remove a required

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. This Surveillance tests the applicable logic associated with the Unit 2 swing bus. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with the Unit 1 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 1. As the Surveillance represents separate tests, the Unit 2 Surveillance should not be performed with Unit 2 in MODE 1, 2, or 3 and the Unit 1 test should not be performed with Unit 1 in MODE 1, 2, or 3.

INSERT 2 - BASES 3.8.1

normally

normally

normally

SR 3.8.1.10

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (12 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, low pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these 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. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations.

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

(continued)

Insert 2 - Bases 3.8.1

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

BASES

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could potentially cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. This Surveillance tests the applicable logic associated with the Unit 2 swing bus. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with the Unit 1 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1 or 2 does not have applicability to Unit 1. As the Surveillance represents separate tests, the Unit 2 Surveillance should not be performed with Unit 2 in MODE 1 or 2 and the Unit 1 test should not be performed with Unit 1 in MODE 1 or 2.

INSERT 1 - BASES 3.8.1

normally

normally

normally

SR 3.8.1.11

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ECCS initiation signal ~~and critical protective functions (engine overspeed, generator differential current, and low lubricating oil pressure) are available to trip the DG to avert substantial damage to the DG unit~~. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

INSERT 3 - BASES 3.8.1

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

The SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from

(continued)

INSERT 3 – Bases 3.8.1

TSTF-400

Non-critical automatic trips are all automatic trips except: a) engine overspeed, b) generator differential current, and c) low lube oil pressure.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

INSERT 2 - BASES 3.8.1

service. Credit may be taken for unplanned events that satisfy this SR. This Surveillance tests the applicable logic associated with the Unit 2 swing bus. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with the Unit 1 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 1. As the Surveillance represents separate tests, the Unit 2 Surveillance should not be performed with Unit 2 in MODE 1, 2, or 3 and the Unit 1 test should not be performed with Unit 1 in MODE 1, 2, or 3.

normally

normally

normally

SR 3.8.1.12

Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3), 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 24 hours. The first 22 hours of this test are performed at ≥ 2775 kW and ≤ 2825 kW (which is near the continuous rating of the DG), and the last 2 hours of this test are performed at ≥ 3000 kW. This is in accordance with commitments described in FSAR Section 8.3 (Ref. 2). The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, and for gradual loading, discussed in SR 3.8.1.2, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor ≤ 0.88. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience. A load band 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.

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

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

This Surveillance has been modified by four 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. However, it is acceptable to perform this SR in MODES 1 and 2 provided the other two DGs are OPERABLE, since a perturbation can only affect one divisional DG. If during the performance of this Surveillance, one of the other DGs becomes operable, this Surveillance is to be suspended. The surveillance may not be performed in MODES 1 and 2 during inclement weather and unstable grid conditions. Credit may be taken for unplanned events that satisfy this SR. Note 3 is provided in recognition that if the offsite electrical power distribution system is lightly loaded (i.e., system voltage is high), it may not be possible to raise voltage without creating an overvoltage condition on the ESF bus. Therefore, to ensure the bus voltage, supplied ESF loads, and DG are not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage or ESF bus loading does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable. To minimize testing of the swing DG, Note 4 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit (no unit specific DG components are being tested). If the swing DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

INSERT 1 - BASES 3.8.1

SR 3.8.1.13

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 12 seconds. The 12 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 24 month Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(5). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

This SR is modified by three Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at near full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing. To minimize testing of the swing DG, Note 3 allows a single test (instead of two tests, one for each unit) to satisfy the requirements for both units. This is allowed since the main purpose of the Surveillance can be met by performing the test on either unit (no unit specific DG components are being tested). If the swing DG fails one of these Surveillances, the DG should be considered inoperable on both units, unless the cause of the failure can be directly related to only one unit.

SR 3.8.1.14

This Surveillance is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6) and ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the load sequence timers are reset.

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

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. This Surveillance tests the applicable logic associated with the Unit 2 swing bus. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with the Unit 1 swing bus. Consequently, a test must be performed within the

INSERT 2 - BASES 3.8.1

(continued)

TSTF-283

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

normally

Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 1. As the Surveillance represents separate tests, the Unit 2 Surveillance should not be performed with Unit 2 in MODE 1, 2, or 3 and the Unit 1 test should not be performed with Unit 1 in MODE 1, 2, or 3.

normally normally

SR 3.8.1.15

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. Although Plant Hatch Unit 2 is not committed to this standard, this SR is consistent with the provisions for automatic switchover required by IEEE-308 (Ref. 12), paragraph 6.2.6(2).

The intent in the requirements associated with SR 3.8.1.15.b is to show that the emergency loading is not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

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

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. This Surveillance tests the applicable logic associated with the Unit 2 swing bus. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with the Unit 1 swing bus. Consequently, a test must be performed within the

INSERT 2 - BASES 3.8.1

(continued)

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

normally

Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 1. As the Surveillance represents separate tests, the Unit 2 Surveillance should not be performed with Unit 2 in MODE 1, 2, or 3 and the Unit 1 test should not be performed with Unit 1 in MODE 1, 2, or 3.

normally normally

SR 3.8.1.16

Under accident conditions, loads are sequentially connected to the bus by the automatic load sequence timing devices. 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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.

INSERT 2 - BASES 3.8.1

normally

This Surveillance tests the applicable logic associated with the Unit 2 swing bus. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with the Unit 1 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 1. As the Surveillance represents separate tests, the Unit 2 Surveillance should not be performed with Unit 2 in MODE 1, 2, or 3 and the Unit 1 test should not be performed with Unit 1 in MODE 1, 2, or 3.

normally normally

(continued)

TSTF-283

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

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, as discussed in the Bases for SR 3.8.1.9, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. 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. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations.

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. 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. This Surveillance tests the applicable logic associated with the Unit 2 swing bus. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with the Unit 1 swing bus. Consequently, a test must be performed within the Frequency contained in the Surveillance Frequency Control Program for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 1. As the Surveillance represents separate tests, the Unit 2 Surveillance should not be performed with Unit 2 in MODE 1, 2, or 3 and the Unit 1 test should not be performed with Unit 1 in MODE 1, 2, or 3.

INSERT 2 - BASES 3.8.1

normally

normally

normally

SR 3.8.1.18

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously. For the purpose of this testing,

(continued)

No change. Included for information only.

BASES (continued)

ACTIONS

A.1

If one or more of the required Unit 1 AC or DC electrical power distribution subsystems are inoperable, and a loss of function has not occurred as described in Condition F, the remaining AC and DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could, however, result in the loss of certain safety functions (e.g., SGT System and LPCI valve load centers), continued power operation should not exceed 7 days. The 7 day Completion Time takes into account the capacity and capability of the remaining AC and DC electrical power distribution subsystems, and is based on the shortest restoration time allowed for the systems affected by the inoperable AC and DC electrical power distribution subsystem in the respective system Specification.

B.1

If a Unit 2 or swing DG DC electrical power distribution subsystem is inoperable, the remaining DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could, however, result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation should not exceed 12 hours. The 12 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining the DG DC electrical power distribution subsystem OPERABLE. (The DG DC electrical power distribution subsystem affects both the DG and the offsite circuit, as well as the breaker closure power for various 4160 VAC loads, but does not affect 125/250 VDC station service loads). The 12 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

a. There is a potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected bus(es) to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. [The redundant component is verified OPERABLE in accordance with Specification 5.5.10, "Safety Function Determination Program (SFDP)."]

(continued)

ACTIONS

~~B.1 (continued)~~

~~The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.7.a. If Condition B is entered while, for instance, a Unit 2 or swing AC bus is inoperable and subsequently returned OPERABLE, LCO 3.8.7.a may already have been not met for up to 8 hours. This situation could lead to a total duration of 20 hours, since initial failure of LCO 3.8.7.a, to restore the Unit 2 and swing DG DC distribution system. At this time a Unit 2 or swing AC bus could again become inoperable, and Unit 2 and swing DC distribution system could be restored OPERABLE. This could continue indefinitely.~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time LCO 3.8.7.a was initially not met, instead of at the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet LCO 3.8.7.a indefinitely.~~

C.1

With one or more required Unit 2 or swing AC buses, load centers, motor control centers, or distribution panels in one subsystem inoperable, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

The Condition C postulated worst scenario is one 4160 V bus without AC power (i.e., no offsite power to the 4160 V bus and the associated DG inoperable). In this condition, the unit is more vulnerable to a complete loss of Unit 2 AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining buses by stabilizing the unit, and on restoring power to the affected buses. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

(continued)

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BASES

ACTIONS

C.1 (continued)

a. There is a potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected bus(es) to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. [The redundant component is verified OPERABLE in accordance with Specification 5.5.10, "Safety Function Determination Program (SFDP)."]

~~The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.7.a. If Condition C is entered while, for instance, a Unit 2 station service DC bus is inoperable and subsequently returned OPERABLE, LCO 3.8.7.a may already have been not met for up to 2 hours. This situation could lead to a total duration of 10 hours, since initial failure of LCO 3.8.7.a, to restore the Unit 2 and swing AC distribution system. At this time a Unit 2 station service DC bus could again become inoperable, and Unit 2 and swing AC distribution system could be restored OPERABLE. This could continue indefinitely.~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time LCO 3.8.7.a was initially not met, instead of at the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet LCO 3.8.7.a indefinitely~~.

D.1

With one Unit 2 station service DC bus inoperable, the remaining DC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required Unit 2 DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

(continued)

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BASES

ACTIONS

D.1 (continued)

Condition D represents one Unit 2 division without adequate DC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation the plant is significantly more vulnerable to a complete loss of all Unit 2 station service DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining division, and restoring power to the affected division.

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without DC power, while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division;

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

~~The second Completion Time for Required Action D.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.7.a. If Condition D is entered while, for instance, Unit 2 or swing AC bus is inoperable and subsequently restored OPERABLE, LCO 3.8.7.a may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of LCO 3.8.7.a, to restore the Unit 2 station service DC distribution system. At this time, Unit 2 or swing AC bus could again become inoperable, and Unit 2 station service DC distribution system could be restored OPERABLE. This could continue indefinitely.~~

(continued)

ACTIONS

~~D.1 (continued)~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time LCO 3.8.7.a was initially not met, instead of at the time Condition D was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.~~

E.1 and E.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit 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.

F.1

Condition F 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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1.3 Completion Times

DESCRIPTION (continued)

a. Must exist concurrent with the first inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extension does not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each division, subsystem, component or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase "from discovery . . ."

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One Function X subsystem inoperable.	A.1	Restore Function X subsystem to OPERABLE status.	7 days
B. One Function Y subsystem inoperable.	B.1	Restore Function Y subsystem to OPERABLE status.	72 hours
C. One Function X subsystem inoperable. AND One Function Y subsystem inoperable.	C.1 OR C.2	Restore Function X subsystem to OPERABLE status. Restore Function Y subsystem to OPERABLE status.	72 hours 72 hours

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-3 (continued)

When one Function X subsystem and one Function Y subsystem are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each subsystem, starting from the time each subsystem was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second subsystem was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected subsystem was declared inoperable (i.e., initial entry into Condition A).

It is possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. However, doing so would be inconsistent with the basis of the Completion Times. Therefore, there shall be administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls shall ensure that the Completion Times for those Conditions are not inappropriately extended.

(continued)

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE	The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated Limiting Conditions for Operation (LCO). An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR, as well as certain Notes in the Surveillance column that modify performance requirements.

Sometimes special situations dictate when the requirements of a Surveillance are to be met. They are "otherwise stated" conditions allowed by SR 3.0.1. They may be stated as clarifying Notes in the Surveillance, as part of the Surveillance, or both.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

The use of "met" or "performed" in these instances conveys specific meanings. A Surveillance is "met" only when the acceptance criteria are satisfied. Known failure of the requirements of a Surveillance, even without a Surveillance specifically being "performed," constitutes a Surveillance not "met." "Performance" refers only to the requirement to specifically determine the ability to meet the acceptance criteria. Some surveillances contain notes that modify the Frequency of performance or the conditions during which the acceptance criteria must be satisfied. For these Surveillances, the MODE-entry restrictions of SR 3.0.4 may not apply. Such a Surveillance is not required to be performed prior to entering a MODE or other specified condition in the Applicability of the associated LCO if any of the following three conditions are satisfied:

(continued)

1.4 Frequency

DESCRIPTION (continued)

a. The Surveillance is not required to be met in the MODE or other specified condition to be entered; or

b. The Surveillance is not required to be met in the MODE or other specified condition to be entered, but has been performed within the specified Frequency (i.e., it is current) and is known not to be failed; or

c. The Surveillance is required to be met, but not performed, in the MODE or other specified condition to be entered, and is known not to be failed.

Examples 1.4-3, 1.4-4, 1.4-5, and 1.4-6 discuss these special situations.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the interval specified in the Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Examples 1.4-3 and 1.4-4), then SR 3.0.3 becomes applicable.

(continued)

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-1 (continued)

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, then SR 3.0.4 becomes applicable. The Surveillance must be performed within the Frequency requirements of SR 3.0.2, as modified by SR 3.0.3, prior to entry into the mode or other specified condition or the LCO is considered not met (in accordance with SR 3.0.1) and LCO 3.0.4 becomes applicable.

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the extension allowed by SR 3.0.2.

"Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Only required to be met in MODE 1. ----------	
Verify leakage rates are within limits.	24 hours

Example 1.4-4 specifies that the requirements of this Surveillance do not have to be met until the unit is in MODE 1. The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour (plus the extension allowed by SR 3.0.2) interval, but the unit was not in MODE 1, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES, even with the 24 hour Frequency exceeded, provided the MODE change was not made into MODE 1. Prior to entering MODE 1 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

EXAMPLE 1.4-5

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Only required to be performed in MODE 1. ----------	
Perform complete cycle of the valve.	7 days

The interval continues, whether or not the unit operation is in MODE 1, 2, or 3 (the assigned Applicability of the associated LCO) between performances.

(continued)

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-5 (continued)

As the Note modifies the required performance of the Surveillance, the Note is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is not in MODE 1, this Note allows entry into and operation in MODES 2 and 3 to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency" if completed prior to entering MODE 1. Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was not in MODE 1, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not result in entry into MODE 1.

Once the unit reaches MODE 1, the requirement for the Surveillance to be performed within its specified Frequency applies and would require that the Surveillance had been performed. If the Surveillance were not performed prior to entering MODE 1, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

EXAMPLE 1.4-6

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Not required to be met in MODE 3. ----------	
Verify parameter is within limits.	24 hours

Example 1.4-6 specifies that the requirements of this Surveillance do not have to be met while the unit is in MODE 3 (the assumed Applicability of the associated LCO is MODES 1, 2, and 3). The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), and the unit was in MODE 3, there would be no failure of the SR nor failure to meet the LCO. Therefore, no

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-6

violation of SR 3.0.4 occurs when changing MODES to enter MODE 3, even with the 24 hour Frequency exceeded, provided the MODE change does not result in entry into MODE 2 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

SURVEILLANCE REQUIREMENTS

----------NOTE----------
During single control rod scram time Surveillances, the control rod drive (CRD) pumps shall be isolated from the associated scram accumulator.

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify each 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 each reactor shutdown ≥ 120 days
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 fuel cell AND Prior to exceeding 40% RTP after work on control rod or CRD System that could affect scram time

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Sodium pentaborate solution not within Region A limits of Figure 3.1.7-1 or 3.1.7-2, but within the Region B limits.	A.1 Restore sodium pentaborate solution to within Region A limits.	72 hours
B. One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	7 days
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1 Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.2	----------NOTE---------- Not required to be performed until 12 hours after THERMAL POWER ≥ 24% RTP. ---------- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 24% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.3	(Not used.)	
SR 3.3.1.1.4	----------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 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.6	(Not used.)	

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.7	(Not used.)	
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	----------NOTE---------- 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 FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.11	Verify Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 27.6% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitor					
a. Neutron Flux - High	2	2[d]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
	5[a]	2[d]	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
b. Inop	2	2[d]	G	SR 3.3.1.1.4 SR 3.3.1.1.15	NA
	5[a]	2[d]	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
2. Average Power Range Monitor					
a. Neutron Flux - High (Setdown)	2	3[c]	G	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 20% RTP
b. Simulated Thermal Power - High	1	3[c]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 0.57W + 56.8% RTP and ≤ 115.5% RTP[b]
c. Neutron Flux - High	1	3[c]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 120% RTP
d. Inop	1, 2	3[c]	G	SR 3.3.1.1.10	NA

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) 0.57W + 56.8% - 0.57 ΔW RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) Each APRM channel provides inputs to both trip systems.

(d) One channel in each quadrant of the core must be OPERABLE whenever the IRMs are required to be OPERABLE. Both the RWM and a second licensed operator must verify compliance with the withdrawal sequence when less than three channels in any trip system are OPERABLE.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.1.2 Verify by administrative methods that startup with RWM inoperable has not been performed in the last 12 months. AND	Immediately
	C.2.2 Verify movement of control rods is in compliance with banked position withdrawal sequence (BPWS) by a second licensed operator or other qualified member of the technical staff.	During control rod movement
D. RWM inoperable during reactor shutdown.	D.1 Verify movement of control rods is in compliance with BPWS by a second licensed operator or other qualified member of the technical staff.	During control rod movement
E. One or more Reactor Mode Switch - Shutdown Position channels inoperable.	E.1 Suspend control rod withdrawal. AND	Immediately
	E.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1
1.	Reactor Steam Dome Pressure	2	E
2.	Reactor Vessel Water Level		
	a. -317 inches to -17 inches	2	E
	b. -150 inches to +60 inches	2	E
	c. 0 inches to +60 inches	2	E
	d. 0 inches to +400 inches	1	NA
3.	Suppression Pool Water Level		
	a. 0 inches to 300 inches	2	E
	b. 133 inches to 163 inches	2	E
4.	Drywell Pressure		
	a. -10 psig to +90 psig	2	E
	b. -5 psig to +5 psig	2	E
	c. 0 psig to +250 psig	2	E
5.	Drywell Area Radiation (High Range)	2	F
6.	Penetration Flow Path Primary Containment Isolation Valve Position	2 per penetration flow path [(a)(b)]	E
7.	(Deleted)		
8.	(Deleted)		
9.	Suppression Pool Water Temperature	2[(c)]	E
10.	Drywell Temperature in Vicinity of Reactor Level Instrument Reference Leg	6	E
11.	Diesel Generator (DG) Parameters		
	a. Output Voltage	1 per DG	NA
	b. Output Current	1 per DG	NA
	c. Output Power	1 per DG	NA
	d. Battery Voltage	1 per DG	NA
12.	RHR Service Water Flow	2	E

(a) Not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Monitoring each of four quadrants.

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

LCO 3.3.6.1 The primary containment isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	12 hours for Functions 2.a, 2.b, 6.b, 7.a, and 7.b AND 24 hours for Functions other than Functions 2.a, 2.b, 6.b, 7.a, and 7.b
B. ----------NOTE---------- Not applicable for Function 5.c. ---------- One or more automatic Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	D.1 Isolate associated main steam line (MSL). OR D.2.1 Be in MODE 3. AND D.2.2 Be in MODE 4.	12 hours 12 hours 36 hours
E. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	E.1 Be in MODE 2.	6 hours
F. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	F.1 Isolate the affected penetration flow path(s).	1 hour
G. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	G.1 Isolate the affected penetration flow path(s).	24 hours
H. As required by Required Action C.1 and referenced in Table 3.3.6.1-1. OR Required Action and associated Completion Time of Condition F or G not met.	H.1 Be in MODE 3. AND H.2 Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	I.1 Declare Standby Liquid Control (SLC) System inoperable.	1 hour
	OR	
	I.2 Isolate the Reactor Water Cleanup (RWCU) System.	1 hour
J. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	J.1 Initiate action to restore channel to OPERABLE status.	Immediately
	OR	
	J.2 Initiate action to isolate the Residual Heat Removal (RHR) Shutdown Cooling System.	Immediately

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

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.5	Perform CHANNEL CALIBRATION.	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

Table 3.3.6.1-1 (page 1 of 5)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level - Low Low Low, Level 1	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ -113 inches
b. Main Steam Line Pressure - Low	1	2	E	SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 825 psig
c. Main Steam Line Flow - High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 138% rated steam flow
d. Condenser Vacuum - Low	1, 2[a], 3[a]	2	D	SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 7 inches Hg vacuum
e. Main Steam Tunnel Temperature - High	1,2,3	6	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 194°F
f. Turbine Building Area Temperature - High	1,2,3	16[b]	D	SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 200°F
2. Primary Containment Isolation					
a. Reactor Vessel Water Level - Low, Level 3	1,2,3	2	H	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches
b. Drywell Pressure - High	1,2,3	2	H	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig

(continued)

(a) With any turbine stop valve not closed.

(b) With 8 channels per trip string. Each trip string shall have 2 channels per main steam line, with no more than 40 ft separating any two OPERABLE channels.

Table 3.3.6.1-1 (page 2 of 5)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Primary Containment Isolation (continued)					
c. Drywell Radiation - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 138 R/hr
d. Reactor Building Exhaust Radiation - High	1,2,3	2	H	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.6	≤ 80 mR/hr
e. Refueling Floor Exhaust Radiation - High	1,2,3	2	H	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.6	≤ 80 mR/hr
3. High Pressure Coolant Injection (HPCI) System Isolation					
a. HPCI Steam Line Flow - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 303% rated steam flow
b. HPCI Steam Supply Line Pressure - Low	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 100 psig
c. HPCI Turbine Exhaust Diaphragm Pressure - High	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 20 psig
d. Drywell Pressure - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig
e. HPCI Pipe Penetration Room Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
f. Suppression Pool Area Ambient Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F

(continued)

Table 3.3.6.1-1 (page 3 of 5)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. HPCI System Isolation (continued)					
g. Suppression Pool Area Temperature - Time Delay Relays	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 16 minutes 15 seconds
h. Suppression Pool Area Differential Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 42°F
i. Emergency Area Cooler Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
4. Reactor Core Isolation Cooling (RCIC) System Isolation					
a. RCIC Steam Line Flow - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 306% rated steam flow
b. RCIC Steam Supply Line Pressure - Low	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 60 psig
c. RCIC Turbine Exhaust Diaphragm Pressure - High	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 20 psig
d. Drywell Pressure - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig
e. RCIC Suppression Pool Ambient Area Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
f. Suppression Pool Area Temperature - Time Delay Relays	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 31 minutes 15 seconds

(continued)

Table 3.3.6.1-1 (page 4 of 5)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. RCIC System Isolation (continued)					
g. RCIC Suppression Pool Area Differential Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 42°F
h. Emergency Area Cooler Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
5. RWCU System Isolation					
a. Area Temperature - High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 150°F
b. Area Ventilation Differential Temperature - High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 67°F
c. SLC System Initiation	1,2	1[c]	I	SR 3.3.6.1.6	NA
d. Reactor Vessel Water Level - Low Low, Level 2	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ -47 inches
6. RHR Shutdown Cooling System Isolation					
a. Reactor Steam Dome Pressure - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 145 psig
b. Reactor Vessel Water Level - Low, Level 3	3,4,5	2 [d]	J	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches

(continued)

(c) SLC System Initiation only inputs into one of the two trip systems.

(d) Only one trip system required in MODES 4 and 5 when RHR Shutdown Cooling System integrity maintained.

Table 3.3.6.1-1 (page 5 of 5)
Primary Containment Isolation Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7.	Traversing Incore Probe System Isolation					
	a. Reactor Vessel Water Level - Low, Level 3	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches
	b. Drywell Pressure - High	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.1 ECCS - Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of six of seven safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except high pressure coolant injection (HPCI) and ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig.

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to HPCI.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable. <u>OR</u> One LPCI pump in both LPCI subsystems inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. HPCI System inoperable.	C.1	Verify by administrative means RCIC System is OPERABLE.	1 hour
	AND		
	C.2	Restore HPCI System to OPERABLE status.	14 days
D. HPCI System inoperable. AND Condition A entered.	D.1	Restore HPCI System to OPERABLE status.	72 hours
	OR		
	D.2	Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours
E. Two or more ADS valves inoperable. OR Required Action and associated Completion Time of Condition C or D not met.	E.1	Be in MODE 3.	12 hours
	AND		
	E.2	Reduce reactor steam dome pressure to ≤ 150 psig.	36 hours
F. Two or more low pressure ECCS injection/spray subsystems inoperable for reasons other than Condition A. OR HPCI System and two or more ADS valves inoperable.	F.1	Enter LCO 3.0.3.	Immediately

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 ----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside primary containment <u>AND</u> 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, for isolation devices inside primary containment
B. ----------NOTE---------- Only applicable to penetration flow paths with two PCIVs. ---------- One or more penetration flow paths with two PCIVs inoperable except due to leakage not within limit.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ----------NOTE---------- Only applicable to penetration flow paths with only one PCIV. ---------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limits.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	4 hours except for excess flow check valve (EFCV) line and penetrations with a closed system AND 72 hours for EFCV line and penetrations with a closed system
	AND	
	C.2 ----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days
D. One or more penetration flow paths with leakage not within limit.	D.1 Restore leakage to within limit.	4 hours
E. Required Action and associated Completion Time of Condition A, B, C, or D not met in MODE 1, 2, or 3.	E.1 Be in MODE 3.	12 hours
	AND	
	E.2 Be in MODE 4.	36 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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
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)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER until all OPERABLE IRM channels ≤ 25/40 divisions of full scale on Range 7.	12 hours
C. Suppression pool average temperature > 105°F. AND Any OPERABLE IRM channel > 25/40 divisions of full scale on Range 7. AND Performing testing that adds heat to the suppression pool.	C.1 Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > 110°F.	D.1 Place the reactor mode switch in the shutdown position. AND D.2 Determine suppression pool average temperature. AND D.3 Be in MODE 4.	Immediately Once per 30 minutes 36 hours

(continued)

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

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Suspend CORE ALTERATIONS.	Immediately
	AND	
	C.3 Initiate action to suspend OPDRVs.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.1	Verify all secondary containment equipment hatches are closed and sealed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.2	Verify one secondary containment access door in each access opening is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.3	----------NOTE---------- The number of standby gas treatment (SGT) subsystem(s) required for this Surveillance is dependent on the secondary containment configuration, and shall be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. ----------	
	Verify secondary containment can be drawn down to ≥ 0.20 inch of vacuum water gauge in ≤ 120 seconds using required standby gas treatment (SGT) subsystem(s).	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.4	----------NOTE---------- The number of SGT subsystem(s) required for this Surveillance is dependent on the secondary containment configuration, and shall be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. ----------	
	Verify the secondary containment can be maintained ≥ 0.20 inch of vacuum water gauge for 1 hour using required SGT subsystem(s) at a flow rate ≤ 4000 cfm.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

LCO 3.6.4.2 Each SCIV shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by SCIVs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more penetration flow paths with one SCIV inoperable.	A.1 Isolate the affected penetration flow path by use of at least one closed and deactivated automatic valve, closed manual valve, or blind flange. AND A.2 ----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means.	8 hours (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days
B. One or more penetration flow paths with two SCIVs inoperable.	B.1 Isolate the affected penetration flow path by use of at least one closed and deactivated automatic valve, closed manual valve, or blind flange.	4 hours
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. Required Action and associated Completion Time of Condition A or B not met during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	D.1 ----------NOTE---------- LCO 3.0.3 is not applicable. ---------- Suspend movement of irradiated fuel assemblies in the secondary containment.	Immediately

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	AND	
	D.2 Suspend CORE ALTERATIONS.	Immediately
	AND	
	D.3 Initiate action to suspend OPDRVs.	Immediately

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 Surveillance Frequency Control 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

3.6 CONTAINMENT SYSTEMS

3.6.4.3 Standby Gas Treatment (SGT) System

LCO 3.6.4.3 The Unit 1 and Unit 2 SGT subsystems required to support LCO 3.6.4.1, "Secondary Containment," shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required Unit 1 SGT subsystem inoperable while: 1. Four SGT subsystems required OPERABLE, and 2. Unit 1 reactor building-to-refueling floor plug not installed.	A.1 Restore required Unit 1 SGT subsystem to OPERABLE status.	30 days from discovery of failure to meet the LCO
B. One required Unit 2 SGT subsystem inoperable. <u>OR</u> One required Unit 1 SGT subsystem inoperable for reasons other than Condition A.	B.1 Restore required SGT subsystem to OPERABLE status.	7 days

(continued)

ACTIONS

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

LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuits.	1 hour AND Once per 8 hours thereafter
	AND		
	A.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4160 V ESF bus concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore required offsite circuit to OPERABLE status.	72 hours
B. One Unit 1 or the swing DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.4 (continued)	AND 14 days for the swing diesel with maintenance restrictions met
C. One required Unit 2 DG inoperable	C.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	C.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	AND	
	C.3.1 Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR	
	C.3.2 Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- 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
SR 3.8.1.7	----------NOTES---------- 1. This Surveillance shall not normally be performed in MODE 1 or 2, except for the swing DG. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. For the swing DG, this Surveillance shall not be performed in MODE 1 or 2 using the Unit 1 controls. Credit may be taken for unplanned events that satisfy this SR. 2. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ---------- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 65.5 Hz; and b. Within 3 seconds following load rejection, the voltage is ≥ 3740 V and ≤ 4580 V.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.8	----------NOTES---------- 1. This Surveillance shall not normally be performed in MODE 1 or 2, except for the swing DG. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. For the swing DG, this Surveillance shall not be performed in MODE 1 or 2 using the Unit 1 controls. Credit may be taken for unplanned events that satisfy this SR. 2. 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. 3. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ----------	
	Verify each DG operating at a power factor ≤ 0.88 does not trip and voltage is maintained ≤ 4800 V during and following a load rejection of ≥ 2775 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ----------	
	Verify on an actual or simulated loss of offsite power 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 ≤ 12 seconds, 2. Energizes auto-connected shutdown loads through automatic load sequence timing devices, 3. Maintains steady state voltage ≥ 3740 V and ≤ 4243 V, 4. Maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. Supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.10	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and: a. In ≤ 12 seconds after auto-start achieves voltage ≥ 3740 V, and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4243 V; b. In ≤ 12 seconds after auto-start achieves frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG's non-critical automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ECCS initiation signal.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not normally be performed in MODE 1 or 2, unless the other two DGs are OPERABLE. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. If either of the other two DGs becomes inoperable, this surveillance shall be suspended. Credit may be taken for unplanned events that satisfy this SR. 3. 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. 4. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ----------	
	Verify each DG operating at a power factor ≤ 0.88 operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 3000 kW; and b. For the remaining hours of the test loaded ≥ 2775 kW and ≤ 2825 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 2565 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. 3. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ---------- Verify each DG starts and achieves, in ≤ 12 seconds, voltage ≥ 3740 V and frequency ≥ 58.8 Hz; and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4243 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.14	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.16	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify interval between each sequenced load block is within ± 10% of design interval for each load sequence timing device.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.17	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ----------	
	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 ≤ 12 seconds, 2. Energizes auto-connected emergency loads through automatic load sequence timing devices, 3. Achieves steady state voltage ≥ 3740 V and ≤ 4243 V, 4. Achieves 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

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One or more (Unit 1 or swing bus) DG DC electrical power distribution subsystems inoperable.	B.1	Restore DG DC electrical power distribution subsystem to OPERABLE status.	12 hours
C. One or more (Unit 1 or swing bus) AC electrical power distribution subsystems inoperable.	C.1	Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours
D. One Unit 1 station service DC electrical power distribution subsystem inoperable.	D.1	Restore Unit 1 station service DC electrical power distribution subsystem to OPERABLE status.	2 hours
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1	Be in MODE 3.	12 hours
	AND		
	E.2	Be in MODE 4.	36 hours
F. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	F.1	Enter LCO 3.0.3.	Immediately

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary as follows:

1) For noble gases, less than or equal to a dose rate of 500 mrem/year to the total body and less than or equal to a dose rate of 3000 mrem/year to the skin, and

2) For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days, less than or equal to a dose rate of 1500 mrem/year to any organ;

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

(continued)

5.5 Programs and Manuals (continued)

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track FSAR Section 4.2, cyclic and transient occurrences, to ensure that reactor coolant pressure boundary components are maintained within the design limits.

5.5.6 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports.

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda are as follows:

ASME Boiler and Pressure Vessel Code and Applicable Addenda Terminology for Inservice Testing Activities	Required Frequencies for Performing Inservice Testing Activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Yearly or annually	At least once per 366 days

b. The provisions of SR 3.0.2 are applicable to the frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

5.5.7 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2, Sections C.5.c and C.5.d, and in accordance with Regulatory Guide 1.52, Revision 2.

(continued)

5.5 Programs and Manuals

5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

The program shall include:

a. The limits for the concentrations of hydrogen in the main condenser offgas treatment system and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion); and

b. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.9 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

1. An API gravity or an absolute specific gravity within limits,

2. A flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

3. A water and sediment content within limits;

b. Within 31 days following addition of the new fuel oil to storage tanks, verify that the properties of the new fuel oil, other than those addressed in a., above, are within limits for ASTM 2D fuel oil; and

(continued)

5.5 Programs and Manuals

5.5.9 Diesel Fuel Oil Testing Program (continued)

c. Total particulate concentration of the fuel oil is ≤ 10 mg/liter when tested every 92 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program surveillance frequencies.

5.5.10 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate limitations and remedial or compensatory actions may be identified to be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, no concurrent loss of offsite power or no concurrent loss of onsite diesel generator(s), a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable.

(continued)

5.5 Programs and Manuals

5.5.10 Safety Function Determination Program (SFDP) (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.11 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

   1. A change in the TS incorporated in the license; or

   2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of item b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not normally be performed in MODE 1 or 2, unless the other two DGs are OPERABLE. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. If either of the other two DGs becomes inoperable, this surveillance shall be suspended. Credit may be taken for unplanned events that satisfy this SR. 3. 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. 4. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ----------	
	Verify each DG operating at a power factor ≤ 0.88 operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 3000 kW; and b. For the remaining hours of the test loaded ≥ 2775 kW and ≤ 2825 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

1.3 Completion Times

DESCRIPTION (continued)

a. Must exist concurrent with the first inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extension does not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each division, subsystem, component or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase "from discovery . . ."

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X subsystem inoperable.	A.1 Restore Function X subsystem to OPERABLE status.	7 days
B. One Function Y subsystem inoperable.	B.1 Restore Function Y subsystem to OPERABLE status.	72 hours
C. One Function X subsystem inoperable. AND One Function Y subsystem inoperable.	C.1 Restore Function X subsystem to OPERABLE status. OR C.2 Restore Function Y subsystem to OPERABLE status.	72 hours 72 hours

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-3 (continued)

When one Function X subsystem and one Function Y subsystem are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each subsystem, starting from the time each subsystem was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second subsystem was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected subsystem was declared inoperable (i.e., initial entry into Condition A).

It is possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. However, doing so would be inconsistent with the basis of the Completion Times. Therefore, there shall be administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls shall ensure that the Completion Times for those Conditions are not inappropriately extended.

(continued)

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated Limiting Conditions for Operation (LCO). An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR, as well as certain Notes in the Surveillance column that modify performance requirements.

Sometimes special situations dictate when the requirements of a Surveillance are to be met. They are "otherwise stated" conditions allowed by SR 3.0.1. They may be stated as clarifying Notes in the Surveillance, as part of the Surveillance, or both.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

The use of "met" or "performed" in these instances conveys specific meanings. A Surveillance is "met" only when the acceptance criteria are satisfied. Known failure of the requirements of a Surveillance, even without a Surveillance specifically being "performed," constitutes a Surveillance not "met." "Performance" refers only to the requirement to specifically determine the ability to meet the acceptance criteria. Some Surveillances contain notes that modify the Frequency of performance or the conditions during which the acceptance criteria must be satisfied. For these Surveillances, the MODE-entry restrictions of SR 3.0.4 may not apply. Such a Surveillance is not required to be performed prior to entering a MODE or other specified condition in the Applicability of the associated LCO if any of the following three conditions are satisfied:

(continued)

1.4 Frequency

DESCRIPTION (continued)

a. The Surveillance is not required to be met in the MODE or other specified condition to be entered; or

b. The Surveillance is required to be met in the MODE or other specified condition to be entered, but has been performed within the specified Frequency (i.e., it is current) and is known not to be failed; or

c. The Surveillance is required to be met, but not performed, in the MODE or other specified condition to be entered, and is known not to be failed.

Examples 1.4-3, 1.4-4, 1.4-5, and 1.4-6 discuss these special situations.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the interval specified in the Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Examples 1.4-3 and 1.4-4), then SR 3.0.3 becomes applicable.

(continued)

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-1 (continued)

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, then SR 3.0.4 becomes applicable. The surveillance must be performed within the Frequency requirements of SR 3.0.2, as modified by SR 3.0.3, prior to entry into the mode or other specified condition or the LCO is considered not met (in accordance with SR 3.0.1) and LCO 3.0.4 becomes applicable.

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the extension allowed by SR 3.0.2.

"Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Only required to be met in MODE 1. ----------	
Verify leakage rates are within limits.	24 hours

Example 1.4-4 specifies that the requirements of this Surveillance do not have to be met until the unit is in MODE 1. The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour (plus the extension allowed by SR 3.0.2) interval, but the unit was not in MODE 1, there would be no failure of the SR nor failure to meet the LCO. Therefore, no violation of SR 3.0.4 occurs when changing MODES, even with the 24 hour Frequency exceeded, provided the MODE change was not made into MODE 1. Prior to entering MODE 1 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

EXAMPLE 1.4-5

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Only required to be performed in MODE 1. ----------	
Perform complete cycle of the valve.	7 days

The interval continues, whether or not the unit operation is in MODE 1, 2, or 3 (the assumed Applicability of the associated LCO) between performances.

(continued)

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-5 (continued)

As the Note modifies the required performance of the Surveillance, the Note is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is not in MODE 1, this Note allows entry into and operation in MODES 2 and 3 to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency" if completed prior to entering MODE 1. Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was not in MODE 1, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not result in entry into MODE 1.

Once the unit reaches MODE 1, the requirement for the Surveillance to be performed within its specified Frequency applies and would require that the Surveillance had been performed, If the Surveillance were not performed prior to entering MODE 1, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

EXAMPLE 1.4-6

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
----------NOTE---------- Not required to be met in MODE 3. ----------	
Verify parameter is within limits.	24 hours

Example 1.4-6 specifies that the requirements of this Surveillance do not have to be met while the unit is in MODE 3 (the assumed Applicability of the associated LCO is MODES 1, 2, and 3). The interval measurement for the Frequency of this Surveillance continues at all times, as described in Example 1.4-1. However, the Note constitutes an "otherwise stated" exception to the Applicability of this Surveillance. Therefore, if the Surveillance were not performed within the 24 hour interval (plus the extension allowed by SR 3.0.2), and the unit was in MODE 3, there would be no failure of the SR nor failure to meet the LCO. Therefore, no

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-6

violation of SR 3.0.4 occurs when changing MODES to enter MODE 3, even with the 24 hour Frequency exceeded, provided the MODE change does not result in entry into MODE 2 (assuming again that the 24 hour Frequency were not met), SR 3.0.4 would require satisfying the SR.

SURVEILLANCE REQUIREMENTS

----------NOTE----------
During single control rod scram time Surveillances, the control rod drive (CRD) pumps shall be isolated from the associated scram accumulator.

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify each 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 each reactor shutdown ≥ 120 days
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 fuel cell AND Prior to exceeding 40% RTP after work on control rod or CRD System that could affect scram time

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Sodium pentaborate solution not within Region A limits of Figure 3.1.7-1 or 3.1.7-2, but within the Region B limits.	A.1 Restore sodium pentaborate solution to within Region A limits.	72 hours
B. One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	7 days
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1 Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	12 hours

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.2	----------NOTE---------- Not required to be performed until 12 hours after THERMAL POWER ≥ 24% RTP. ---------- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 24% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.3	(Not used.)	
SR 3.3.1.1.4	----------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 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.6	(Not used.)	

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.7	(Not used.)	
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	----------NOTE---------- 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 FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.11	Verify Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 27.6% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitor					
a. Neutron Flux - High	2	2[d]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
	5[a]	2[d]	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
b. Inop	2	2[d]	G	SR 3.3.1.1.4 SR 3.3.1.1.15	NA
	5[a]	2[d]	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
2. Average Power Range Monitor					
a. Neutron Flux - High (Setdown)	2	3[c]	G	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 20% RTP
b. Simulated Thermal Power - High	1	3[c]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 0.57W + 56.8% RTP and ≤ 115.5% RTP[b]
c. Neutron Flux - High	1	3[c]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 120% RTP
d. Inop	1, 2	3[c]	G	SR 3.3.1.1.10	NA

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) 0.57W + 56.8% - 0.57 ΔW RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) Each APRM channel provides inputs to both trip systems.

(d) One channel in each quadrant of the core must be OPERABLE whenever the IRMs are required to be OPERABLE. Both the RWM and a second licensed operator must verify compliance with the withdrawal sequence when less than three channels in any trip system are OPERABLE.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.1.2 Verify by administrative methods that startup with RWM inoperable has not been performed in the last 12 months. AND C.2.2 Verify movement of control rods is in compliance with banked position withdrawal sequence (BPWS) by a second licensed operator or other qualified member of the technical staff.	Immediately During control rod movement
D. RWM inoperable during reactor shutdown.	D.1 Verify movement of control rods is in compliance with BPWS by a second licensed operator or other qualified member of the technical staff.	During control rod movement
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

Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1
1.	Reactor Steam Dome Pressure	2	E
2.	Reactor Vessel Water Level		
	a. -317 inches to -17 inches	2	E
	b. -150 inches to +60 inches	2	E
	c. 0 inches to +60 inches	2	E
	d. 0 inches to +400 inches	1	NA
3.	Suppression Pool Water Level		
	a. 0 inches to 300 inches	2	E
	b. 133 inches to 163 inches	2	E
4.	Drywell Pressure		
	a. -10 psig to +90 psig	2	E
	b. -5 psig to +5 psig	2	E
	c. 0 psig to +250 psig	2	E
5.	Drywell Area Radiation (High Range)	2	F
6.	Penetration Flow Path Primary Containment Isolation Valve Position	2 per penetration flow path[(a)(b)]	E
7.	(Deleted)		
8.	(Deleted)		
9.	Suppression Pool Water Temperature	2[(c)]	E
10.	Drywell Temperature in Vicinity of Reactor Level Instrument Reference Leg	6	E
11.	Diesel Generator (DG) Parameters		
	a. Output Voltage	1 per DG	NA
	b. Output Current	1 per DG	NA
	c. Output Power	1 per DG	NA
	d. Battery Voltage	1 per DG	NA
12.	RHR Service Water Flow	2	E

(a) Not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Monitoring each of four quadrants.

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

LCO 3.3.6.1 The primary containment isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

----------NOTES----------
1. Penetration flow paths may be unisolated intermittently under administrative controls
2. Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	12 hours for Functions 2.a, 2.b, 6.b, 7.a, and 7.b AND 24 hours for Functions other than Functions 2.a, 2.b, 6.b, 7.a, and 7.b
B. ----------NOTE---------- Not applicable for Function 5.c. ---------- One or more automatic Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	D.1 Isolate associated main steam line (MSL). OR D.2.1 Be in MODE 3. AND D.2.2 Be in MODE 4.	12 hours 12 hours 36 hours
E. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	E.1 Be in MODE 2.	6 hours
F. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	F.1 Isolate the affected penetration flow path(s).	1 hour
G. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	G.1 Isolate the affected penetration flow path(s).	24 hours
H. As required by Required Action C.1 and referenced in Table 3.3.6.1-1. OR Required Action and associated Completion Time of Condition F or G not met.	H.1 Be in MODE 3. AND H.2 Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	I.1 Declare Standby Liquid Control (SLC) System inoperable.	1 hour
	OR	
	I.2 Isolate the Reactor Water Cleanup (RWCU) System.	1 hour
J. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	J.1 Initiate action to restore channel to OPERABLE status.	Immediately
	OR	
	J.2 Initiate action to isolate the Residual Heat Removal (RHR) Shutdown Cooling System.	Immediately

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

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.5	Perform CHANNEL CALIBRATION.	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
SR 3.3.6.1.7	----------NOTE---------- Channel sensors are excluded. ---------- Verify the ISOLATION SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program

Table 3.3.6.1-1 (page 1 of 5)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level - Low Low Low, Level 1	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ -113 inches
b. Main Steam Line Pressure - Low	1	2	E	SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 825 psig
c. Main Steam Line Flow - High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 138% rated steam flow
d. Condenser Vacuum - Low	1, 2[a], 3[a]	2	D	SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 7 inches Hg vacuum
e. Main Steam Tunnel Temperature - High	1,2,3	6	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 194°F
f. Turbine Building Area Temperature - High	1,2,3	16[b]	D	SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 200°F
2. Primary Containment Isolation					
a. Reactor Vessel Water Level - Low, Level 3	1,2,3	2	H	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches
b. Drywell Pressure - High	1,2,3	2	H	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig

(continued)

(a) With any turbine stop valve not closed.

(b) With 8 channels per trip string. Each trip string shall have 2 channels per main steam line, with no more than 40 ft separating any two OPERABLE channels.

Table 3.3.6.1-1 (page 2 of 5)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Primary Containment Isolation (continued)					
c. Drywell Radiation - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 138 R/hr
d. Reactor Building Exhaust Radiation - High	1,2,3	2	H	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.6	≤ 80 mR/hr
e. Refueling Floor Exhaust Radiation - High	1,2,3	2	H	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.6	≤ 80 mR/hr
3. High Pressure Coolant Injection (HPCI) System Isolation					
a. HPCI Steam Line Flow - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 303% rated steam flow
b. HPCI Steam Supply Line Pressure - Low	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 100 psig
c. HPCI Turbine Exhaust Diaphragm Pressure - High	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 20 psig
d. Drywell Pressure - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig
e. HPCI Pipe Penetration Room Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
f. Suppression Pool Area Ambient Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F

(continued)

Table 3.3.6.1-1 (page 3 of 5)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. HPCI System Isolation (continued)					
g. Suppression Pool Area Temperature - Time Delay Relays	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 16 minutes 15 seconds
h. Suppression Pool Area Differential Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 42°F
i. Emergency Area Cooler Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
4. Reactor Core Isolation Cooling (RCIC) System Isolation					
a. RCIC Steam Line Flow - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 307% rated steam flow
b. RCIC Steam Supply Line Pressure - Low	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 60 psig
c. RCIC Turbine Exhaust Diaphragm Pressure - High	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 20 psig
d. Drywell Pressure - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig
e. RCIC Suppression Pool Ambient Area Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
f. Suppression Pool Area Temperature - Time Delay Relays	1,2,3	1	F	SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 31 minutes 15 seconds

(continued)

Table 3.3.6.1-1 (page 4 of 5)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. RCIC System Isolation (continued)					
g. RCIC Suppression Pool Area Differential Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 42°F
h. Emergency Area Cooler Temperature - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 169°F
5. RWCU System Isolation					
a. Area Temperature - High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 150°F
b. Area Ventilation Differential Temperature - High	1,2,3	1 per area	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 67°F
c. SLC System Initiation	1,2	1(c)	I	SR 3.3.6.1.6	NA
d. Reactor Vessel Water Level - Low Low, Level 2	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ - 47 inches
6. RHR Shutdown Cooling System Isolation					
a. Reactor Steam Dome Pressure - High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 145 psig
b. Reactor Vessel Water Level - Low, Level 3	3,4,5	2(d)	J	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches

(c) SLC System Initiation only inputs into one of the two trip systems.

(d) Only one trip system required in MODES 4 and 5 when RHR Shutdown Cooling System integrity maintained.

Table 3.3.6.1-1 (page 5 of 5)
Primary Containment Isolation Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7.	Traversing Incore Probe System Isolation					
	a. Reactor Vessel Water Level - Low, Level 3	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 0 inches
	b. Drywell Pressure - High	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 1.92 psig

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.1 ECCS - Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of six of seven safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except high pressure coolant injection (HPCI) and ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig.

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to HPCI.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable. <u>OR</u> One LPCI pump in both LPCI subsystems inoperable	A.1 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. HPCI System inoperable.	C.1	Verify by administrative means RCIC System is OPERABLE.	1 hour
	AND		
	C.2	Restore HPCI System to OPERABLE status.	14 days
D. HPCI System inoperable. AND Condition A entered.	D.1	Restore HPCI System to OPERABLE status.	72 hours
	OR		
	D.2	Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours
E. Two or more ADS valves inoperable. OR Required Action and associated Completion Time of Condition C or D not met.	E.1	Be in MODE 3.	12 hours
	AND		
	E.2	Reduce reactor steam dome pressure to ≤ 150 psig.	36 hours
F. Two or more low pressure ECCS injection/spray subsystems inoperable for reasons other than Condition A. OR HPCI System and two or more ADS valves inoperable.	F.1	Enter LCO 3.0.3.	Immediately

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 ----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside primary containment <u>AND</u> 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, for isolation devices inside primary containment
B. ----------NOTE---------- Only applicable to penetration flow paths with two PCIVs. ---------- One or more penetration flow paths with two PCIVs inoperable except due to leakage not within limit.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ----------NOTE---------- Only applicable to penetration flow paths with only one PCIV. ---------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limits.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	4 hours except for excess flow check valve (EFCV) line and penetrations with a closed system AND 72 hours for EFCV line and penetrations with a closed system
	AND	
	C.2 ----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days
D. One or more penetration flow paths with leakage not within limit.	D.1 Restore leakage to within limit.	4 hours
E. Required Action and associated Completion Time of Condition A, B, C, or D not met in MODE 1, 2, or 3.	E.1 Be in MODE 3.	12 hours
	AND	
	E.2 Be in MODE 4.	36 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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
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)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1 Reduce THERMAL POWER until all OPERABLE IRM channels ≤ 25/40 divisions of full scale on Range 7.	12 hours
C. Suppression pool average temperature > 105°F. AND Any OPERABLE IRM channel > 25/40 divisions of full scale on Range 7. AND Performing testing that adds heat to the suppression pool.	C.1 Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > 110°F.	D.1 Place the reactor mode switch in the shutdown position. AND D.2 Determine suppression pool average temperature. AND D.3 Be in MODE 4.	Immediately Once per 30 minutes 36 hours

(continued)

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

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Suspend CORE ALTERATIONS. AND C.3 Initiate action to suspend OPDRVs.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.1	Verify all secondary containment equipment hatches are closed and sealed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.2	Verify one secondary containment access door in each access opening is closed.	In accordance with the Surveillance Frequency Control Program
SR 3.6.4.1.3	----------NOTE---------- The number of standby gas treatment (SGT) subsystem(s) required for this Surveillance is dependent on the secondary containment configuration, and shall be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. ---------- Verify secondary containment can be drawn down to ≥ 0.20 inch of vacuum water gauge in ≤ 120 seconds using required standby gas treatment (SGT) subsystem(s).	 In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.4	----------NOTE---------- The number of SGT subsystem(s) required for this Surveillance is dependent on the secondary containment configuration, and shall be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. ----------	
	Verify the secondary containment can be maintained ≥ 0.20 inch of vacuum water gauge for 1 hour using required SGT subsystem(s) at a flow rate ≤ 4000 cfm.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

LCO 3.6.4.2 Each SCIV shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of irradiated fuel assemblies in the secondary containment,
During CORE ALTERATIONS,
During operations with a potential for draining the reactor vessel (OPDRV).

ACTIONS

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

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by SCIVs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more penetration flow paths with one SCIV inoperable.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND A.2 ----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means.	8 hours

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	2. Isolation devices that are locked, sealed, or otherwise secured may be verified by administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days
B. One or more penetration flow paths with two SCIVs inoperable.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	4 hours
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. Required Action and associated Completion Time of Condition A or B not met during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	D.1 ----------NOTE---------- LCO 3.0.3 is not applicable. ---------- Suspend movement of irradiated fuel assemblies in the secondary containment.	Immediately

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	AND	
	D.2 Suspend CORE ALTERATIONS.	Immediately
	AND	
	D.3 Initiate action to suspend OPDRVs.	Immediately

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 Surveillance Frequency Control 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 (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required Unit 2 SGT subsystem inoperable. OR One required Unit 1 SGT subsystem inoperable for reasons other than Condition A.	B.1 Restore required SGT subsystem to OPERABLE status.	7 days
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, or 3.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. Required Action and associated Completion Time of Condition A or B not met during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs.	----------NOTE---------- LCO 3.0.3 is not applicable. ---------- D.1 Place remaining OPERABLE SGT subsystem(s) in operation. OR D.2.1 Suspend movement of irradiated fuel assemblies in secondary containment. AND D.2.2 Suspend CORE ALTERATIONS. AND D.2.3 Initiate action to suspend OPDRVs.	 Immediately Immediately Immediately Immediately

(continued)

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuits.	1 hour AND Once per 8 hours thereafter
	AND		
	A.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4160 V ESF bus concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore required offsite circuit to OPERABLE status.	72 hours
B. One Unit 2 or the swing DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.4 (continued)	AND 14 days for the swing diesel with maintenance restrictions met
C. One required Unit 1 DG inoperable.	C.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	C.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	AND	
	C.3.1 Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR	
	C.3.2 Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- 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
SR 3.8.1.7	----------NOTES---------- 1. This Surveillance shall not normally be performed in MODE 1 or 2, except for the swing DG. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. For the swing DG, this Surveillance shall not be performed in MODE 1 or 2 using the Unit 2 controls. Credit may be taken for unplanned events that satisfy this SR. 2. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ---------- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 65.5 Hz; and b. Within 3 seconds following load rejection, the voltage is ≥ 3740 V and ≤ 4580 V.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.8	----------NOTES---------- 1. This Surveillance shall not normally be performed in MODE 1 or 2, except for the swing DG. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. For the swing DG, this Surveillance shall not be performed in MODE 1 or 2 using the Unit 2 controls. Credit may be taken for unplanned events that satisfy this SR. 2. 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. 3. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ---------- Verify each DG operating at a power factor ≤ 0.88 does not trip and voltage is maintained ≤ 4800 V during and following a load rejection of ≥ 2775 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated loss of offsite power 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 ≤ 12 seconds, 2. Energizes auto-connected shutdown loads through automatic load sequence timing devices, 3. Maintains steady state voltage ≥ 3740 V and ≤ 4243 V, 4. Maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. Supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.10	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and: a. In ≤ 12 seconds after auto-start achieves voltage ≥ 3740 V, and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4243 V; b. In ≤ 12 seconds after auto-start achieves frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ----------	
	Verify each DG's non-critical automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ECCS initiation signal.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	----------NOTES---------- 1: Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not normally be performed in MODE 1 or 2, unless the other two DGs are OPERABLE. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. If either of the other two DGs becomes inoperable, this Surveillance shall be suspended. Credit may be taken for unplanned events that satisfy this SR. 3. 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. 4. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ----------	
	Verify each DG operating at a power factor ≤ 0.88 operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 3000 kW; and b. For the remaining hours of the test loaded ≥ 2775 kW and ≤ 2825 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 2565 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. 3. For the swing DG, a single test at the specified Frequency will satisfy this Surveillance for both units. ---------- Verify each DG starts and achieves, in ≤ 12 seconds, voltage ≥ 3740 V and frequency ≥ 58.8 Hz; and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4243 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.14	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.16	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify interval between each sequenced load block is within ± 10% of design interval for each load sequence timing device.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.17	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1, 2, or 3. However, this surveillance may be performed to establish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ---------- 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 ≤ 12 seconds, 2. Energizes auto-connected emergency loads through automatic load sequence timing devices, 3. Achieves steady state voltage ≥ 3740 V and ≤ 4243 V, 4. Achieves 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

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One or more (Unit 2 or swing bus) DG DC electrical power distribution subsystems inoperable.	B.1	Restore DG DC electrical power distribution subsystem to OPERABLE status.	12 hours
C. One or more (Unit 2 or swing bus) AC electrical power distribution subsystems inoperable.	C.1	Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours
D. One Unit 2 station service DC electrical power distribution subsystem inoperable.	D.1	Restore Unit 2 station service DC electrical power distribution subsystem to OPERABLE status.	2 hours
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1	Be in MODE 3.	12 hours
	AND		
	E.2	Be in MODE 4.	36 hours
F. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	F.1	Enter LCO 3.0.3.	Immediately

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary as follows:

1) For noble gases, less than or equal to a dose rate of 500 mrem/year to the total body and less than or equal to a dose rate of 3000 mrem/year to the skin, and

2) For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days, less than or equal to a dose rate of 1500 mrem/year to any organ;

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

(continued)

5.5 Programs and Manuals (continued)

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track FSAR Section 5.2, cyclic and transient occurrences, to ensure that reactor coolant pressure boundary components are maintained within the design limits.

5.5.6 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports.

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda are as follows:

ASME Boiler and Pressure Vessel Code and Applicable Addenda Terminology for Inservice Testing Activities	Required Frequencies for Performing Inservice Testing Activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Yearly or annually	At least once per 366 days

b. The provisions of SR 3.0.2 are applicable to the frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

5.5.7 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2, Sections C.5.c and C.5.d, and in accordance with Regulatory Guide 1.52, Revision 2.

(continued)

5.5 Programs and Manuals

5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

The program shall include:

a. The limits for the concentrations of hydrogen in the main condenser offgas treatment system and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion); and

b. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.9 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

   1. An API gravity or an absolute specific gravity within limits,

   2. A flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

   3. A water and sediment content within limits;

b. Within 31 days following addition of the new fuel oil to storage tanks, verify that the properties of the new fuel oil, other than those addressed in a., above, are within limits for ASTM 2D fuel oil; and

(continued)

5.5 Programs and Manuals

5.5.9 Diesel Fuel Oil Testing Program (continued)

c. Total particulate concentration of the fuel oil is ≤ 10 mg/liter when tested every 92 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program surveillance frequencies.

5.5.10 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate limitations and remedial or compensatory actions may be identified to be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross division checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, no concurrent loss of offsite power or no concurrent loss of onsite diesel generator(s), a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable.

(continued)

5.5 Programs and Manuals

5.5.9 Safety Function Determination Program (SFDP) (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.11 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

   1. A change in the TS incorporated in the license; or

   2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of item b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

(continued)

Edwin I. Hatch Nuclear Plant
Request for Technical Specifications Amendment
Adoption of Generic Technical Specification Changes

Enclosure 5

Copies of T-Travelers

Technical Specification Task Force
Improved Standard Technical Specifications Change Traveler

Removing Restart of Shutdown Clock for Increasing Suppression Pool Temperature

NUREGs Affected: ☐ 1430 ☐ 1431 ☐ 1432 ☑ 1433 ☑ 1434

Note: This "T" Traveler has been reviewed and approved by the Technical Specification Task Force and is made available as a template for plant-specific license amendments. This Traveler has not been reviewed and approved by the Nuclear Regulatory Commission.

Classification: 3) Improve Specifications Recommended for CLIIP?: No

Correction or Improvement: Correction NRC Fee Status: Not Exempt

Industry Contact: Bert Morris, (256) 729-7909, bcmorris3@tva.gov

1.0 Description

The ACTIONS of Specification 3.6.2.1, Suppression Pool Average Temperature, are revised to correct the tracking of Completion Times.

2.0 Proposed Change

ISTS 3.6.2.1, ACTIONS D and E both require the plant to be in MODE 4 within 36 hours. ACTION D is entered when the suppression pool average temperature is > 100 F but <= 120°F. ACTION E is entered when the suppression pool average temperature is > 120 F. This change revises the entry condition for ACTION D to "suppression pool average temperature > 110 F" and removes the "Be in MODE 4" Required Action from ACTION E. This eliminates having two Required Actions and Completion Times, both directing enty into MODE 4, with staggered Completion Times.

3.0 Background

ISTS 3.6.2.1, ACTIONS D and E currently allow a resetting of the shutdown requirement (Be in MODE 4 within 36 hours) when the suppression pool average temperature rises above 120 F. This occurs because the Condition of ACTION D is no longer met when temperature exceeds 120 F and therefore, the Required Actions are no longer applicable. The entry conditions of ACTION E are met when temperature exceeds 120 F and a new Completion Time clock begins for ACTION E. If temperature drops below 120 F, Condition E no longer applies and the Completion Time clock of Condition D is restarted at zero.

4.0 Technical Analysis

The current construction of the ACTIONS is inconsistent with the intent to promptly bring the reactor to a condition in which the LCO does not apply. Removing the upper limit of the entry condition for ACTION D would require the shutdown Required Action of Condition D to continue to be applicable if temperature increases above 120 F. ACTION E would also be applicable and require the reactor vessel to be depressurized below 200 psig within 12 hours.

Required Action D.2 is changed to "verify suppression pool average temperature is <= 120 F" to "Determine supression pool average temperature" since Required Action D.2 would apply when the temperature is > 120 F.

A similar change is not needed for ACTION A since ACTION B provides the appropriate default actions for noncompliance with Required Action A.1.

5.0 Regulatory Analysis

5.1 No Significant Hazards Consideration

The TSTF has evaluated whether or not a significant hazards consideration is involved with the proposed generic change by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change revises the Required Actions of Specification 3.6.2.1, Suppression Pool Average Temperature. The proposed changes do not adversely affect accident the design assumptions, conditions, or configuration of the facility. The conditions represented in the ACTIONS are not an initiator to any accident previously evaluated. The consequences of an accident under the revised ACTIONS are no different than under the current ACTIONS.

   Therefore, it is concluded that this change does not significantly increase the probability or consequences of an accident previously evaluated.

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

   Response: No.

   The proposed change revises the Required Actions of Specification 3.6.2.1, Suppression Pool Average Temperature. This revision will not impact the accident analysis. The changes will not alter the methods of operation of any system. No new or different accidents result. The changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed) or a change in the methods governing normal plant operation. The changes do not alter assumptions made in the safety analysis.

   Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created.

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

   Response: No.

   The proposed change revises the Required Actions of Specification 3.6.2.1, Suppression Pool Average Temperature. The proposed revision will not adversely affect the margin of safety as it corrects the ACTIONS to provide appropriate compensatory measures when suppression pool average temperature is greater than the limit.

   Therefore, it is concluded that this change does not involve a significant reduction in the margin of safety.

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

5.2 Applicable Regulatory Requirements/Criteria

The proposed change to the Improved Standard Technical Specifications corrects the ACTIONS to provide appropriate compensatory measures. In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the approval of the proposed change will not be inimical to the common defense and security or to the health and safety of the public.

6.0 Environmental Consideration

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

7.0 References

None.

Revision History

OG Revision 0 Revision Status: Closed

Revision Proposed by: BWROG

Revision Description:
Original Issue

Owners Group Review Information

Date Originated by OG: 21-Mar-00

Owners Group Comments:
2/14/2001 - discussed by TSTF. Not applicable to PWRs. Needs Safety Evaluation quality justification.

Owners Group Resolution: Superceeded Date: 21-Mar-00

OG Revision 1 Revision Status: Active

Revision Proposed by: BWROG

Revision Description:
Revised to mark on Revision 2 pages and to reformat the justification.

OG Revision 1 **Revision Status: Active**

Owners Group Review Information

Date Originated by OG: 21-May-03

Owners Group Comments:
(No Comments)

Owners Group Resolution: Approved Date: 21-May-03

TSTF Review Information

TSTF Received Date: 08-Aug-03 Date Distributed for Review: 12-Aug-03

OG Review Completed: ☑ BWOG ☑ WOG ☑ CEOG ☑ BWROG

TSTF Comments:
(No Comments)

TSTF Resolution: Approved for Use Date: 26-Aug-03

Affected Technical Specifications

Action 3.6.2.1.D	Suppression Pool Average Temperature
Action 3.6.2.1.E	Suppression Pool Average Temperature
Action 3.6.2.1.E Bases	Suppression Pool Average Temperature

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1	Reduce THERMAL POWER [until all OPERABLE IRM channels ≤ [25/40] divisions of full scale on Range 7] [to ≤ 1% RTP.]	12 hours
C. Suppression pool average temperature > [105]°F. AND [Any OPERABLE IRM channel > [25/40] divisions of full scale on Range 7] [THERMAL POWER > 1% RTP]. AND Performing testing that adds heat to the suppression pool.	C.1	Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > [110]°F but ~~≤ [120]°F~~.	D.1	Place the reactor mode switch in the shutdown position.	Immediately
	AND		
	D.2	~~Verify~~ Determine suppression pool average temperature ~~≤ [120]°F~~.	Once per 30 minutes
	AND		
	D.3	Be in MODE 4.	36 hours

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.	24 hours AND 5 minutes when performing testing that adds heat to the suppression pool

BASES

ACTIONS (continued)

C.1

Suppression pool average temperature is allowed to be > [95]°F [when any OPERABLE IRM channel is > [25/40] divisions of full scale on Range 7] [with THERMAL POWER > 1% RTP], and when testing that adds heat to the suppression pool is being performed. However, if temperature is > [105]°F, all testing must be immediately suspended to preserve the heat absorption capability of the suppression pool. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1 and D.2

Suppression pool average temperature > [110]°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further cooldown to Mode 4 is required at normal cooldown rates (provided pool temperature remains ≤ [120]°F). Additionally, when suppression pool temperature is > [110]°F, increased monitoring of pool temperature is required to ensure that it remains ≤ [120]°F. The once per 30 minute Completion Time is adequate, based on operating 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.

Additionally, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 4 within 36 hours.

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

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1	Reduce THERMAL POWER [until all OPERABLE IRM channels are ≤ [25/40] divisions of full scale on Range 7] [to ≤ 1% RTP].	12 hours
C. Suppression pool average temperature > [105]°F. AND [Any OPERABLE IRM channel > [25/40] divisions of full scale on Range 7] [THERMAL POWER > 1% RTP]. AND Performing testing that adds heat to the suppression pool.	C.1	Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > [110]°F but ≤ [120]°F.	D.1	Place the reactor mode switch in the shutdown position.	Immediately
	AND		
	D.2	Verify suppression pool average temperature is ≤ [120]°F.	Once per 30 minutes
	AND		
	D.3	Be in MODE 4.	36 hours

Determine

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.	24 hours AND 5 minutes when performing testing that adds heat to the suppression pool

BASES

ACTIONS (continued)

on Range 7 for all OPERABLE IRM channels] [≤ 1% RTP] within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power in an orderly manner and without challenging plant systems.

C.1

Suppression pool average temperature is allowed to be > [95]°F [with any OPERABLE IRM channel > [25/40] divisions of full scale on Range 7] [with THERMAL POWER > 1% RTP] when testing that adds heat to the suppression pool is being performed. However, if temperature is > [105]°F, the testing must be immediately suspended to preserve the pool's heat absorption capability. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1 and D.2

Suppression pool average temperature > [110]°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further cooldown to MODE 4 is required at normal cooldown rates (provided pool temperature remains ≤ [120]°F). Additionally, when pool temperature is > [110]°F, increased monitoring of pool temperature is required to assure that it remains ≤ [120]°F. The once per 30 minute Completion Time is adequate, based on operating experience. Given the high pool 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.

Additionally, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 4 within 36 hours.

E.1 and E.2

If suppression pool average temperature cannot be maintained ≤ [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 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 without challenging plant systems.

is

Technical Specification Task Force
Improved Standard Technical Specifications Change Traveler

Clarify the Control Rod Block Instrumentation Required Action

NUREGs Affected: ☐ 1430 ☐ 1431 ☐ 1432 ☑ 1433 ☐ 1434

Note: This "T" Traveler has been reviewed and approved by the Technical Specification Task Force and is made available as a template for plant-specific license amendments. This Traveler has not been reviewed and approved by the Nuclear Regulatory Commission.

Classification: 1) Technical Change Recommended for CLIIP?: No

Correction or Improvement: Correction

Industry Contact: Bert Morris, (256) 729-7909, bcmorris3@tva.gov

1.0 Description

Technical Specification 3.3.2.1, Control Rod Block Instrumentation, Required Action C.2.1.2, requires verification by administrative means that startup with the Rod Worth Minimizer (RWM) inoperable has not been performed in the last calendar year. The Bases to Required Action C.2.1.2 states that verification is required that a reactor startup with an inoperable RWM was not performed in the last 12 months. This change revises the Technical Specification to be consistent with the Bases.

2.0 Proposed Change

Required Action C.2.1.2 is revised from "Verify by administrative methods that startup with RWM inoperable has not been performed in the last calendar year" to "Verify by administrative methods that startup with RWM inoperable has not been performed in the last 12 months."

3.0 Background

The purpose of the RWM is to control rod patterns during startup, such that only specified control rod sequences and relative positions are allowed over the operating range from all control rods inserted to 10% RTP. The sequences effectively limit the potential amount and rate of reactivity increase during a control rod drop accident (CRDA). Prescribed control rod sequences are stored in the RWM, which will initiate control rod withdrawal and insert blocks when the actual sequence deviates beyond allowances from the stored sequence. The RWM determines the actual sequence based position indication for each control rod. The RWM also uses feedwater flow and steam flow signals to determine when the reactor power is above the preset power level at which the RWM is automatically bypassed. The RWM is a single channel system that provides input into both RMCS rod block circuits.

Condition C applies when the RWM is inoperable during reactor startup. In this Condition, Required Action C.2.1.1 requires verification that >= 12 rods are withdrawn or verification by administrative methods that startup with RWM inoperable has not been performed in the last 12 months.

4.0 Technical Justification

With the RWM inoperable during a reactor startup, the operator is still capable of enforcing the prescribed control rod sequence. However, the overall reliability is reduced because a single operator error can result in violating the control rod sequence. Therefore, control rod movement must be immediately suspended except by scram. Alternatively, startup may continue if at least 12 control rods have already been withdrawn, or a reactor startup with an inoperable RWM was not performed in the last 12 months. The purpose of the 12 month restriction is to enforce infrequent occurrences of reactor startup with the RWM inoperable.

The Technical Specifications state the period in Required Action C.2.1.2 as "the last calendar year." This phrase is ambiguous, because it can be interpreted as the proceeding 12 months (current date - 12 months) or the last year (January through December). If interpreted as the last year, it would allow using Required Action C.2.1.2 on December 31 and again on January 1 of the following year. This was not the intent of the Required Action. The Bases wording, "last 12 months," is unambiguous and is adopted in the Specification.

5.0 Regulatory Analysis

5.1 No Significant Hazards Consideration

The TSTF has evaluated whether or not a significant hazards consideration is involved with the proposed generic change by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change revises a Required Action to limit startup with the Rod Worth Minimizer (RWM) inoperable from once per calendar year to once per 12 months. The RWM is used to minimize the possibility and consequences of a control rod drop accident. This change clarifies the intent of the limitation, but does not affect the requirement for the RWM to be operable. As, over time, the number of startups with the RWM inoperable will not increase, the probability of any accident previously evaluated is not significantly increase. As the RWM is still required to be operable, the consequences of an 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. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   The proposed change revises a Required Action to limit startup with the Rod Worth Minimizer inoperable from once per calendar year to once per 12 months. No new or different accidents result from utilizing the proposed change. The changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed) or a significant change in the methods governing normal plant operation. The changes do not alter assumptions made in the safety analysis. The proposed changes are 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. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.
   The proposed change revises a Required Action to limit startup with the Rod Worth Minimizer (RWM) inoperable from once per calendar year to once per 12 months. This clarifies the intent of the Required Action. The number of startups with RWM inoperable is not increased.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

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

5.2 Applicable Regulatory Requirements/Criteria

The proposed change does not affect the design requirements or operability requirements of any plant system. In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the approval of the proposed change will not be inimical to the common defense and security or to the health and safety of the public.

6.0 Environmental Consideration

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

7.0 References

None.

Revision History

OG Revision 0 Revision Status: Active

Revision Proposed by: BWROG

Revision Description:
Original Issue

Owners Group Review Information

Date Originated by OG: 21-May-03

Owners Group Comments
(No Comments)

Owners Group Resolution: Approved Date: 21-May-03

TSTF Review Information

TSTF Received Date: 14-Aug-03 Date Distributed for Review 15-Aug-03

OG Review Completed: ☑ BWOG ☑ WOG ☑ CEOG ☑ BWROG

TSTF Comments:
(No Comments)

TSTF Resolution: Approved for Use Date: 12-Sep-03

Affected Technical Specifications

Action 3.3.2.1.C Control Rod Block Instrumentation

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
	C.2.1.2 Verify by administrative methods that startup with RWM inoperable has not been performed in the last calendar year. (12 months)	Immediately
	AND	
	C.2.2 Verify movement of control rods is in compliance with banked position withdrawal sequence (BPWS) by a second licensed operator or other qualified member of the technical staff.	During control rod movement
D. RWM inoperable during reactor shutdown.	D.1 Verify movement of control rods is in compliance with BPWS by a second licensed operator or other qualified member of the technical staff.	During control rod movement
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

Information only

BASES

ACTIONS

- REVIEWER'S NOTE -
Certain LCO Completion Times are based on approved topical reports. In order for the licensee to use the times, the licensee must justify the Completion Times as required by the staff Safety Evaluation Report (SER) for the topical report.

A.1

With one RBM channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod block function; however, overall reliability is reduced because a single failure in the remaining OPERABLE channel can result in no control rod block capability for the RBM. For this reason, Required Action A.1 requires restoration of the inoperable channel to OPERABLE status. The Completion Time of 24 hours is based on the low probability of an event occurring coincident with a failure in the remaining OPERABLE channel.

B.1

If Required Action A.1 is not met and the associated Completion Time has expired, the inoperable channel must be placed in trip within 1 hour. If both RBM channels are inoperable, the RBM is not capable of performing its intended function; thus, one channel must also be placed in trip. This initiates a control rod withdrawal block, thereby ensuring that the RBM function is met.

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

C.1, C.2.1.1, C.2.1.2, and C.2.2

With the RWM inoperable during a reactor startup, the operator is still capable of enforcing the prescribed control rod sequence. However, the overall reliability is reduced because a single operator error can result in violating the control rod sequence. Therefore, control rod movement must be immediately suspended except by scram. Alternatively, startup may continue if at least 12 control rods have already been withdrawn, or a reactor startup with an inoperable RWM was not performed in the last 12 months. Required Actions C.2.1.1 and C.2.1.2 require verification of these conditions by review of plant logs and control room indications. Once Required Action C.2.1.1 or C.2.1.2 is satisfactorily completed, control rod withdrawal may proceed in accordance with the restrictions

Edwin I. Hatch Nuclear Plant
Request for Technical Specifications Amendment
Adoption of Generic Technical Specification Changes

Enclosure 6

Summary of Regulatory Commitments

Summary of Regulatory Commitments

The following table identifies the regulatory commitments in this document. Any other statements in this submittal represent intended or planned actions. They are provided for information purposes and are not considered to be regulatory commitments.

REGULATORY COMMITMENTS	DUE DATE / EVENT
1. A statement will be added to the FSAR similar to the following regarding the performance of logic testing for critical emergency diesel generator trip functions: "The critical emergency diesel generator protective trip functions (i.e., engine overspeed, generator differential current, and low lube oil pressure) are tested periodically per station procedures. The critical protective trip functions are tested by inputting or simulating appropriate signals and demonstrating that the associated instrumentation logic will function to actuate a trip of the emergency diesel generator."	90 days from NRC approval of LAR
2. SNC commits to revise Operations procedure 31GO-OPS-006-0 to include a statement similar to the following: "Alternating between LCO Conditions, in order to allow indefinite continued operation while not meeting the LCO, is not allowed."	90 days from NRC approval of LAR