5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The station manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

5.1.2 A unit supervisor shall be responsible for the control room command function (Since the control room is common to both units, the control room command function for both units can be satisfied by a single unit supervisor). During any absence of the unit supervisor from the control room while the unit is in MODE 1, 2, or 3, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the unit supervisor from the control room while the unit is in MODE 4 or 5 or defueled, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.2 Organization

5.2.2 Unit Staff (continued)

non-licensed operators shall be assigned to each unit.

b. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and Specifications 5.2.2.a and 5.2.2.f for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. A radiation protection technician shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

d. The amount of overtime worked by unit staff members performing safety related functions shall be limited and controlled in accordance with the NRC Policy Statement on working hours (Generic Letter 82-12).

e. The operations manager or shift operations supervisor shall hold an SRO license.

f. The Shift Technical Advisor (STA) shall provide advisory technical support to the shift manager in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. In addition, the STA shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

5.0 6.0 ADMINISTRATIVE CONTROLS

5.1 6.1 RESPONSIBILITY ~~ORGANIZATION~~ A.1 ITS 5.1

<SEE ITS 5.2>

A. Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting the safety of the nuclear power plant.

1. Lines of authority, responsibility, and communication shall be established and defined for the highest management levels through intermediate levels to and including all operating organization positions. These relationships shall be documented and updated, as appropriate, in the form of organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Quality Assurance Manual.

M.1 LA.1

5.1.1 2. The individual filling the ANSI N18.1-1971 Section 4.2.1 position of Plant Manager ("~~Plant~~ Station Manager"), shall be responsible for overall unit safe operation and shall delegate in writing the succession to this responsibility during his absence ~~and shall have~~ control over those onsite activities necessary for safe operation and maintenance of the plant.

<SEE ITS 5.2>

3. The Chief Nuclear Officer (CNO) shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety.

4. The individuals who train the operating staff and those who carry out health physics and quality assurance functions may report to the appropriate onsite manager; however, they shall have sufficient organizational freedom to ensure their independence from operating pressures.

LA.2

~~B. The Shift Manager shall be responsible for directing and commanding the overall operation of the facility on his shift. The primary management responsibility of the Shift Manager shall be for safe operation of the nuclear facility on his shift under all conditions.~~

<SEE ITS 5.2> C. The shift manning for the station shall be as shown in Figure 6.1-3.

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A.1

ITS 5.1

<See ITS 5.2>

1. At least one licensed Reactor Operator shall be in the control room when fuel is in the reactor. In addition, while the reactor is in OPERATIONAL CONDITION 1, 2 or 3, at least one licensed Senior Reactor Operator who has been designated by the Shift Manager to assume the control room direction responsibility shall be in the Control Room. LA.1 A.3

5.1.2

2. A radiation protection technician* shall be on site when fuel is in the reactor.

3. All CORE ALTERATIONS shall be observed and directly supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation.

4. DELETED

5. The Independent Safety Engineering Group (ISEG) shall function to examine unit operating characteristics, NRC issuances, industry advisories, Licensee Event Reports and other sources of plant design and operating experience information, including plants of similar design, which may indicate areas for improving unit safety. The ISEG shall be composed of at least three, dedicated, full-time engineers of multi-disciplines located on site and shall be augmented on a part-time basis by personnel from other parts of the Commonwealth Edison Company organization to provide expertise not represented in the group. The ISEG shall be responsible for maintaining surveillance of unit activities to provide independent verification# that these activities are performed correctly and that human errors are reduced as much as practical. The ISEG shall make detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities or other means of improving unit safety to the Manager of Quality and Safety Assessment and the Plant Manager.

6. The Shift Technical Advisor shall provide advisory technical support to the Shift Manager in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit.

* The radiation protection technician position may be less than the minimum requirement for a period of time not to exceed two hours in order to accommodate unexpected absence provided immediate action is taken to fill the required position.

\# Not responsible for sign-off feature.

<See ITS 5.2>

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FIGURE 6.1-3
MINIMUM SHIFT CREW COMPOSITION[a][c]

POSITION[b]	MINIMUM CREW NUMBER		
	EACH UNIT IN CONDITION 1, 2, OR 3	ONE UNIT IN CONDITION 1, 2, OR 3, AND ONE UNIT IN CONDITION 4 OR 5 OR DEFUELED	EACH UNIT IN CONDITION 4 OR 5 OR DEFUELED
SM	1	1	1
SRO	1	1	None
RO	3	3	2
AO	3	3	3
STA[d]	1	1	None

(a) This table reflects the total requirements for shift staffing of both units.

<SEE ITS 5.2> With the exception of the Shift Manager, the shift crew composition may be one less than the minimum requirements of Figure 6.1-3 for not more than 2 hours to accommodate unexpected absence of on-duty shift crew members, provided immediate action is taken to restore the shift crew composition to within the minimum requirements of Figure 6.1-3. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

(b) Table Notation:

SM Shift Manager with a Senior Reactor Operator license for each unit whose reactor contains fuel.

SRO Individual with a Senior Reactor Operator license for each unit whose reactor contains fuel.

During CORE ALTERATIONS on either unit a licensed SRO or licensed SRO limited to fuel handling, who has no other concurrent responsibilities, must be present to observe and directly supervise this operation.

RO An Individual with a Reactor Operator license or a Senior Reactor Operator license for unit assigned. At least one RO shall be assigned to each unit whose reactor contains fuel. Individuals acting as relief operators shall hold a license for both units. Otherwise, for each unit, provide a relief operator who holds a license for the unit assigned.

AO At least one auxiliary operator shall be assigned to each unit whose reactor contains fuel.

STA Shift Technical Advisor.

5.1.2 (c) While either unit is in CONDITION 1, 2, or 3, an individual with a valid SRO license shall be designated to assume the control room command function. With both Units in CONDITION 4 or 5 or defueled, an individual with a valid SRO or RO license shall be designated to assume the control room command function.

<SEE ITS 5.2> (d) The STA position shall be filled by an individual who meets the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift. A.2

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5.0 6.0 ADMINISTRATIVE CONTROLS

5.1 6.1 RESPONSIBILITY ~~ORGANIZATION~~

A.1

ITS 5.1

SEE ITS 5.2

A. Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting the safety of the nuclear power plant.

1. Lines of authority, responsibility, and communication shall be established and defined for the highest management levels through intermediate levels to and including all operating organization positions. These relationships shall be documented and updated, as appropriate, in the form of organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Quality Assurance Manual.

M.1

5.1.1

and shall delegate in writing the succession to this responsibility during his absence

LA.1

2. The individual filling the ANSI N18.1-1971 Section 4.2.1 position of Plant Manager ("~~Plant~~ Manager"), shall be responsible for overall unit safe operation and shall have control over those onsite activities necessary for safe operation and maintenance of the plant.

station

SEE ITS 5.2

3. The Chief Nuclear Officer (CNO) shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety.

4. The individuals who train the operating staff and those who carry out health physics and quality assurance functions may report to the appropriate onsite manager; however, they shall have sufficient organizational freedom to ensure their independence from operating pressures.

B. ~~The Shift Manager shall be responsible for directing and commanding the overall operation of the facility on his shift. The primary management responsibility of the Shift Manager shall be for safe operation of the nuclear facility on his shift under all conditions.~~

LA.2

SEE ITS 5.2

C. The shift manning for the station shall be as shown in Figure 6.1-3.

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1 D

ITS 5.1

A.1

<See ITS 5.2>

1. At least one licensed Reactor Operator shall be in the control room when fuel is in the reactor. In addition, while the reactor is in OPERATIONAL CONDITION 1, 2 or 3, at least one licensed Senior Reactor Operator who has been designated by the Shift Manager to assume the control room direction responsibility shall be in the Control Room. LA.1 A.3

5.1.2

2. A radiation protection technician* shall be on site when fuel is in the reactor.

3. All CORE ALTERATIONS shall be observed and directly supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation.

4. DELETED

5. The Independent Safety Engineering Group (ISEG) shall function to examine unit operating characteristics, NRC issuances, industry advisories, Licensee Event Reports and other sources of plant design and operating experience information, including plants of similar design, which may indicate areas for improving unit safety. The ISEG shall be composed of at least three, dedicated, full-time engineers of multi-disciplines located on site and shall be augmented on a part-time basis by personnel from other parts of the Commonwealth Edison Company organization to provide expertise not represented in the group. The ISEG shall be responsible for maintaining surveillance of unit activities to provide independent verification# that these activities are performed correctly and that human errors are reduced as much as practical. The ISEG shall make detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities or other means of improving unit safety to the Manager of Quality and Safety Assessment and the Plant Manager. D

6. The Shift Technical Advisor shall provide advisory technical support to the Shift Manager in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit.

* The radiation protection technician position may be less than the minimum requirement for a period of time not to exceed two hours in order to accommodate unexpected absence provided immediate action is taken to fill the required position.

\# Not responsible for sign-off feature.

<See ITS 5.2>

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FIGURE 6.1-3

MINIMUM SHIFT CREW COMPOSITION[a][c]

POSITION[b]	MINIMUM CREW NUMBER		
	EACH UNIT IN CONDITION 1, 2, OR 3	ONE UNIT IN CONDITION 1, 2, OR 3, AND ONE UNIT IN CONDITION 4 OR 5 OR DEFUELED	EACH UNIT IN CONDITION 4 OR 5 OR DEFUELED
SM	1	1	1
SRO	1	1	None
RO	3	3	2
AO	3	3	3
STA[d]	1	1	None

<SEE ITS 5.2>

(a) This table reflects the total requirements for shift staffing of both units.

With the exception of the Shift Manager, the shift crew composition may be one less than the minimum requirements of Figure 6.1-3 for not more than 2 hours to accommodate unexpected absence of on-duty shift crew members, provided immediate action is taken to restore the shift crew composition to within the minimum requirements of Figure 6.1-3. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

(b) Table Notation:

SM Shift Manager with a Senior Reactor Operator license for each unit whose reactor contain: fuel.

SRO Individual with a Senior Reactor Operator license for each unit whose reactor contains fue

During CORE ALTERATIONS on either unit a licensed SRO or licensed SRO limited to fuel handling, who has no other concurrent responsibilities, must be present to observe and directly supervise this operation.

RO An Individual with a Reactor Operator license or a Senior Reactor Operator license for uni assigned. At least one RO shall be assigned to each unit whose reactor contains fuel. Individuals acting as relief operators shall hold a license for both units. Otherwise, for eac unit, provide a relief operator who holds a license for the unit assigned.

AO At least one auxiliary operator shall be assigned to each unit whose reactor contains fuel.

STA Shift Technical Advisor.

5.1.2 (c) While either unit is in CONDITION 1, 2, or 3, an individual with a valid SRO license shall be designated to assume the control room command function. With both Units in CONDITION 4 or 5 or defueled an individual with a valid SRO or RO license shall be designated to assume the control room command function. A.2

<SEE ITS 5.2> (d) The STA position shall be filled by an individual who meets the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

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ADMINISTRATIVE

A.1 In the conversion of the LaSalle 1 and 2 current Technical Specifications (CTS) to the proposed plant specific Improved Technical Specifications (ITS), certain wording preferences or conventions are adopted that do not result in technical changes (either actual or interpretational). Editorial changes, reformatting, and revised numbering are adopted to make the ITS consistent with the BWR Standard Technical Specifications, NUREG 1434, Rev. 1 (i.e., the Improved Standard Technical Specifications (ISTS)).

A.2 Footnote (c) of CTS Figure 6.1-3 requires an individual with an SRO or RO license to be designated to assume the control room command function. The condition of defueled has been added in proposed TS 5.1.2. This requirement is consistent with current plant practice and ensures all possible conditions in which licensed personnel are required are covered. Since this omission is essentially an oversight in the CTS, the change is considered administrative.

A.3 CTS 6.1.C.1 requires that the Shift Manager designate the individual who assumes the control room command function. ITS 5.1.2 includes the individual who is normally designated, the unit supervisor, in lieu of stating that the Shift Manager will designate an individual. Since the unit supervisor is the individual normally designated (as described in procedures), this change is considered administrative.

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Proposed ITS 5.1.1 requires the plant manager to delegate in writing the succession of the responsibility for overall plant operations during his absence. This change is in addition to the responsibility currently required by the CTS, and is consistent with the BWR ITS, NUREG-1434, Rev. 1. Therefore, this more restrictive change is acceptable.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 CTS 6.1.A.2 uses the title "Plant Manager." In ITS 5.1.1, this specific title is replaced with the generic title "station manager." In addition, CTS 6.1.C.1 uses the specific title when referring to the control room command function. ITS 5.1.2 uses only a generic title. The specific titles are proposed to be relocated to the Quality Assurance (QA) Manual. The allowance to relocate the specific title out of the Technical Specifications is consistent with the NRC letter from

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) C. Grimes to the Owners Groups Technical Specification Committee Chairmen, dated November 10, 1994. The various requirements of the station manager are still retained in the ITS. In addition, the ITS also requires the plant specific titles to be in the QA Manual. Therefore, the relocated specific titles are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the QA Manual are controlled by the provisions of 10 CFR 50.54.

LA.2 CTS 6.1.B delineates the responsibility of the Shift Manager for directing and commanding the overall operation of the facility on his shift. This requirement is relocated to the UFSAR. ITS 5.1.2 contains the requirement that a unit supervisor shall be responsible for the control room command function. In addition, during the absence of the unit supervisor while the unit is in MODE 1, 2, or 3, an individual with an active SRO license shall be designated to assume the control room command function, and during the absence of the unit supervisor while the unit is in MODE 4 or 5 or defueled, an individual with an active SRO license or Reactor Operator (RO) license shall be designated to assume the control room command function. Since ITS 5.1.2 provides requirements for the control room command function, inclusion of the detailed responsibilities of the Shift Manager in the ITS is not required to provide adequate protection of the public health and safety. Changes to the UFSAR are controlled by the provisions of 10 CFR 50.59.

"Specific"

None

RELOCATED SPECIFICATIONS

None

TSTF-65 Reviewer's Note Not Shown 1

TSTF-65
<CTS>

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

<6.1.A.2> 5.1.1 The ~~[Plant Superintendent]~~ Station manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence. 2 TSTF-65

~~The [Plant Superintendent] or his designee shall approve, prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety.~~ 3

Fig 6.1-3 footnote (c)

<6.1.C.1> 5.1.2 A ~~The~~ ~~[Shift Supervisor (SS)]~~ unit supervisor shall be responsible for the control room command function. During any absence of the [SS] from the control room while the unit is in MODE 1, 2, or 3, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the [SS] from the control room while the unit is in MODE 4 or 5, or defueled, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function. 2 4 D

(Since the control room is common to both units, the control room command function for both units can be satisfied by a single unit supervisor) 4 D

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS 5.1 - RESPONSIBILITY

1. This reviewer's note has been deleted. This information is for the NRC reviewer to be keyed in to what is needed to meet the TSTF-65 allowance. This is not meant to be retained in the final version of the plant specific submittal.

2. The brackets have been removed and the proper plant specific information has been provided.

3. The second paragraph of ISTS 5.1.1, regarding review and approval of tests or experiments is deleted. CTS do not delineate this requirement. D

4. ISTS 5.1.2 is revised to reflect plant practice. D

<CTS>

5.2 Organization

5.2.2 Unit Staff (continued)

~~shall be assigned for each control room from which a reactor is operating in MODES 1, 2, or 3.~~ [5]

~~Two unit sites with both units shutdown or defueled require a total of three non-licensed operators for the two units.~~

<6.1.C.1> <Fig. 6.1-3 footnote (b)> [TSTF-258]

~~b. At least one licensed Reactor Operator (RO) shall be present in the control room when fuel is in the reactor. In addition, while the unit is in MODE 1, 2, or 3, at least one licensed Senior Reactor Operator (SRO) shall be present in the control room.~~

<Fig 6.1-3 footnote(a)>

b ~~c~~. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and Specification [6] 5.2.2.a and 5.2.2.f ~~g~~ [TSTF-258] for a period of time not to [2] ~~be~~ exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

<6.1.C.2> <6.1.C.2 footnote *>

c ~~d~~. A ~~Health Physics Technician~~ radiation protection technician [1] shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position. [TSTF-65]

~~e. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety related functions (e.g., licensed SROs, licensed ROs, health physicists, auxiliary operators, and key maintenance personnel).~~ [1]

~~Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work an [8 or 12] hour day, nominal 40 hour week, while the unit is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance, or major plant modification, on a temporary basis the following guidelines shall be followed:~~

(continued)

1. The brackets have been removed and the proper plant specific information has been provided.

2. Typographical/grammatical error corrected.

3. Changes have been made (additions, deletions, and/or changes to the NUREG) to reflect the plant specific nomenclature, number, reference, system description, analysis description, or licensing basis description.

5. Editorial changes made for enhanced clarity.

6. Changes have been made to ISTS 5.2.2.a to be consistent with current licensing basis.

6. The referenced requirements are Specifications, not CFR requirements. Therefore, the word "Specifications" has been added to clearly state that "5.2.2.a and 5.2.2.f" are Specifications.

7. The proper plant specific description of the individual to whom the STA provides technical support has been provided.

8. ISTS 5.2 (Organization) is revised by TSTF-258, Rev. 4. In order to maintain consistency, to the maximum extent practicable, between the Administrative Controls Technical Specifications of the ComEd nuclear stations, the following changes of TSTF-258, Rev. 4 are not incorporated in ITS 5.2:

   a. ISTS 5.2.2.e contains requirements for control of overtime of the plant staff. These requirements were revised by TSTF-258, Rev. 4.

   b. ISTS 5.2.2.g contains requirements for the Shift Technical Advisor. The title "Shift Technical Advisor (STA)" was deleted by TSTF-258, Rev. 4.

   Not incorporating these changes to ISTS 5.2 is consistent with the NRC approved ITS for the ComEd Byron and Braidwood Stations.

ATTACHMENT 3

Revision D to Quad Cities Nuclear Power Station, Units 1 and 2
Proposed Improved Technical Specifications Submittal
dated March 3, 2000

Revision D to Quad Cities Nuclear Power Station Improved Technical Specifications Summary of Changes

This attachment provides a brief summary of the changes in Revision D of the proposed Improved Technical Specifications (ITS) submittal for Quad Cities Nuclear Power Station, Units 1 and 2. The original Technical Specifications amendment request (i.e., Revision 0) was submitted to the NRC by letter dated March 3, 2000, as revised in Revisions A, B, and C, submitted to the NRC by letters dated June 5, 2000, September 1, 2000, and December 18, 2000, respectively.

Changes committed to based on discussions with the NRC reviewers, minor technical changes, and editorial corrections are included in this revision.

Chapter 1.0

1. Typographical error has been corrected (changed the word "page" to "pages" in the Dose Equivalent I-131 definition). The change affects ITS 1.1 page 1.1-3 and the Improved Standard Technical Specifications (ISTS) markup page 1.1-3.

2. Markup error has been corrected (added the word "valve" in the TURBINE BYPASS SYSTEM RESPONSE TIME definition). This change affects the ISTS 1.1 markup page 1.1-7.

Section 2.0

1. Markup error has been corrected (added the word "reactor" and pressure units designation "psig"). This change affects the ISTS 2.1.1 Bases markup page B 2.0-3.

Section 3.1

1. Markup error has been corrected (deleted the duplicate word "sequence" from ACTION D). This change affects the ISTS 3.1.3 markup page 3.1-9.

2. Typographical correction has been made to ITS 3.1.3 (Inserted text "occupies a location adjacent to one "slow" control rod, and the one "slow" control rod"), consistent with TSTF-32. This change affects the ISTS 3.1.3 Bases markup insert page B 3.1-15.

3. The word "boron" in the second Frequency in SR 3.1.7.5 has been changed to "sodium pentaborate" to be consistent with the words in the actual SR. This change affects the ISTS 3.1.7 markup page 3.1-21.

Section 3.3

1. Markup error has been corrected (added the word "for" in ACTIONS Note 2), consistent with the Dresden and LaSalle Note. The change affects the ISTS 3.3.1.1 markup page 3.3-1.

2. Typographical/editorial corrections have been made to ITS 3.3.1.1 (The identification of the correct Function number in SR 3.3.1.1.16 Note 2, and the deletion of the second "the" in SR 3.3.1.1.18 Note 2). These changes affect ITS 3.3.1.1 pages 3.3.1.1-6 and the ISTS markup pages 3.3-5 and 3.3-6.

3. The Allowable Values for ITS 3.3.1.1 Functions 2.b (clamped Allowable Value only) and 2.c have been changed to be consistent with the Allowable Value for the same Function in the LaSalle ITS. The new Allowable Values are consistent with the current setpoint calculations. The change affects ITS 3.3.1.1 pages 3.3.1.1-7 and 3.3.1.1-8, and the ISTS markup pages 3.3-7 and 3.3-8.

4. Markup errors have been corrected (the words for Function 3 were shown inserted in the wrong position, as was the accompanying "s" on signal, and deleted letter "s" from "receives" in SR 3.3.1.1.3 Bases). The changes affect the ISTS 3.3.1.1 Bases markup pages B 3.3-13 and B 3.3-27.

5. The term "calendar year" has been changed to "12 months" as requested by the NRC. This change affects ITS 3.3.2.1 page 3.3.2.1-2 and Bases page B 3.3.2.1-7, the Discussion of Changes (DOC) for ITS 3.3.2.1, DOC M.4 (page 3), the ISTS markup page 3.3-16, the Justification for Deviations (JFD) to ITS 3.3.2.1, JFD 7 (page 1), and the ISTS Bases markup page B 3.3-49.

6. The Frequency for SR 3.3.2.1.5 has been changed from 24 months to 92 days, consistent with the actual trip setpoint methodology for the RBM channels. In addition the designation RTP has been included following 30%. These changes affect ITS 3.3.2.1 page 3.3.2.1-4 and Bases page B 3.3.2.1-11 and the ISTS markup pages 3.3-18 and Bases page B 3.3-52.

7. Markup error has been corrected (inserted SR 3.3.2.1.9 for Function 2). The change affects the ISTS 3.3.2.1 markup page 3.3-20.

8. Markup errors have been corrected (revised words inserted in Background to include ...rod "is" selected... and deleted the redundant words "for" in SR 3.3.2.1.2 Bases). The changes affect the ISTS 3.3.2.1 Bases markup pages B 3.3-44 and B 3.3-52.

9. Markup error has been corrected (added "pressure" into the Function 1 words, consistent with the Dresden Bases). The change affects ISTS 3.3.3.1 Bases markup page B 3.3-65.

10. The Allowable Values for the Core Spray Pump Start - Time Delay Relay and Low Pressure Coolant Injection Pump Start - Time Delay Relay Pumps B and D, have been modified to be consistent with the current setpoint analyses. These changes affect ITS 3.3.5.1 pages 3.3.5.1-10 and 3.3.5.1-11, and the ISTS markup insert page 3.3-42 and page 3.3-43.

11. Markup errors have been corrected (the word "the" in Table 3.3.5.1-1 footnote a has been lined out, the "4" in Table 3.3.5.1-1 has been deleted for the Required Channels for Core Spray Pump Discharge Pressure-High, the word "flow" in the Background discussion of HPCI flow monitoring instrumentation has been deleted, the location of the word "is" has been properly identified in the discussion for the Core Spray Pump Discharge Flow - Low Function, the word "is" has been changed to "are" in the discussion of the LPCI Pump Start - Time Delay Relay, the word "level" has been deleted in the discussion of the Reactor Vessel Water Level - Low Low, and the insert to ACTIONS E.1 and E.2 have been changed to delete the word "control" and add a period at the end of the

statement). These changes affect the ISTS 3.3.5.1 markup pages 3.3-44, 3.3-45 and Bases pages B 3.3-104, B 3.3-111, B 3.3-114, B 3.3-120 and B 3.3-131.

12. The Applicable Safety Analyses Bases for the Contaminated Condensate Storage Tank Level - Low Function, and ACTIONS D.1, D.2.1, and D.2.2 Bases have been modified for clarity, as requested by the NRC. This change affects ITS 3.3.5.1 Bases pages B 3.3.5.1-22 and B 3.3.5.1-33 and the ISTS Bases markup pages B 3.3-117 and B 3.3-129.

13. A typographical error has been corrected in ITS 3.3.5.1 Bases ACTIONS G.1 and G.2, the reference to Function 5.g has been changed to 5.f. The change affects ITS 3.3.5.1 Bases page B 3.3.5.1-38 and the ISTS Bases markup page B 3.3-134.

14. Markup error has been corrected (in Table 3.3.5.2-1 Function 3, the acronym (CCST) was moved to the proper location). The change affects the ISTS 3.3.5.2 markup page 3.3-51.

15. The Applicable Safety Analyses Bases for the Contaminated Condensate Storage Tank Level - Low Function, and ACTIONS D.1, D.2.1, and D.2.2 Bases have been modified, for clarity, as requested by the NRC. In addition, the redundant word "the" in the ACTIONS D.1, D.2.1, and D.2.2 Bases has been deleted. These changes affect ITS 3.3.5.2 Bases pages B 3.3.5.2-5 and B 3.3.5.2-9 and the ISTS Bases markup pages B 3.3-143 and B 3.3-146.

16. Markup errors have been corrected (in Table 3.3.6.1-1, for the RCIC Turbine Area Temperature - High, SR 3.3.6.1.4 has been changed to SR 3.3.6.1.6 and in ITS 3.3.6.1 Bases Background for the Shutdown Cooling System Isolation the letter "s" has been deleted). The changes affect the ISTS 3.3.6.1 markup page 3.3-61 and Bases page B 3.3-155.

17. A typographical error has been corrected in the Bases of ITS 3.3.6.1 (Function 1.c should be Function 1.d). The change affects ITS 3.3.6.1 Bases page B 3.3.6.1-22 and the ISTS Bases markup page B 3.3-177.

18. Markup error has been corrected (in the ITS 3.3.7.1 Bases for ACTIONS C.1 and C.2, the word "performs" has been added since it was inadvertently crossed out). The change affects the ISTS 3.3.7.1 Bases markup page B 3.3-214.

19. An editorial error has been corrected in ITS 3.3.7.2 (the mechanical vacuum pump trip system contains only one breaker and vacuum pump, therefore the use of the term "associated" and references to multiple breaker"(s)" has been deleted). This change affects ITS 3.3.7.2 page 3.3.7.2-2 and Bases pages B 3.3.7.2-1, B 3.3.7.2-5, and B 3.3.7.2-7, and the ISTS markup insert page 3.3.7.2-2 and Bases markup insert pages B 3.3.7.2-1, B 3.3.7.2-5, and B 3.3.7.2-7.

<u>Section 3.4</u>

1. The change committed to during discussions with the NRC to resolve an issue related to SR 3.4.2.1 has been made. This change affects ITS 3.4.2 Bases pages B 3.4.2-4 and B 3.4.2-5 the ISTS Bases markup pages B 3.4-10 and B 3.4-11.

2. Typographical/editorial changes have been made, for consistency, in the Bases Background of ITS 3.4.3 (changed " these valves" to "which", specifically identified low set "relief" valves, annotated insert to state all "of the" relief valves, and added "s" to function). These changes affect ITS 3.4.3 Bases page B 3.4.3-1 and the ISTS Bases markup pages B 3.4-12 and B 3.4-14.

3. The word "Identify" has been changed to "Verify," as requested by the NRC. In addition, the acronym "IGSCC" has been identified. These changes affect ITS 3.4.4 page 3.4.4-2 and Bases page B 3.4.4-4 and the ISTS markup page 3.4-8 and Bases page B 3.4-20.

4. Markup error has been corrected (word "radioactivity" has been crossed out, consistent with other places in the Bases). The change affects the ISTS 3.4.5 Bases markup page B 3.4-28.

5. Markup error has been corrected (symbol "<" has been changed to words "less than," consistent with the Dresden and LaSalle ITS). The change affects the ISTS 3.4.7 Bases markup page 3.4-18.

6. The Bases statement of ITS 3.4.8 ACTION A.1 concerning LCO Notes 1 and 2 has been revised to include only Note 2 and the Bases statement of ACTION A.2 and A.3 concerning Note 1 has been deleted since, when using LCO Note 1, the ACTIONS would not be entered. This change affects ITS 3.4.8 Bases pages B 3.4.8-3 and B 3.4.8-4 and the ISTS Bases markup pages B 3.4-44 and B 3.4-45.

7. Markup error has been corrected (the word "the" has been included in the insert to SR 3.4.9.3 and SR 3.4.9.4). The change affects the ISTS 3.4.9 Bases markup page B 3.4-53.

Section 3.5

1. Markup errors have been corrected (word "safety/" has been crossed out in LCO, Background words "and to" were inserted into the correct location, and the inserted "s" in SR 3.5.1.4 has been deleted). The changes affect the ISTS 3.5.1 markup page 3.5-1 and Bases pages B 3.5-3 and B3.5-12.

2. The LCO Bases for the ITS 3.5.1 and ITS 3.5.2 and associated Surveillance Requirements SR 3.5.1.2 and SR 3.5.2.3 have been revised as requested by the NRC. These changes affect ITS 3.5.1 Bases pages B 3.5.1-6 and B 3.5.1-11, the Bases markup page B 3.5-5, insert pages B 3.5-5 and B 3.5-10, the ITS 3.5.2 Bases pages B 3.5.2-2 and B 3.5.2-6, and the ISTS Bases insert pages B 3.5-18 and B 3.5-22.

3. Markup error has been corrected (word "required" has been added to Required Action C.1, consistent with the Condition). This change affects ISTS 3.5.2 markup page 3.5-7.

4. The change committed to during discussion with the NRC to resolve a beyond scope issue related to the amount of water required in the contaminated condensate storage tanks has been made. This change affects ITS 3.5.2 page 3.5.2-3 and Bases pages B 3.5.2-1, B 3.5.2-4, and B 3.5.2-5, the CTS markup for ITS 3.5.2, pages 1 of 4, 2 of 4, and 3 of 4, the Discussion of Changes for ITS

3.5.2, DOC L.5 (deleted from page 7), the ISTS markup page 3.5-9 and Bases markup pages B 3.5-17 and B 3.5-20, and the No Significant Hazards Consideration, NSHC L.5 (deleted).

5. The Bases for ITS 3.5.2 have been modified to include the information relocated by ITS 3.5.2 DOC LA.1. This change affects ITS 3.5.2 Bases page B 3.5.2-1 and the ISTS Bases markup page B 3.5-17.

Section 3.6

1. The change committed to during discussions with the NRC to resolve a beyond scope issue related to the drywell-to-suppression chamber bypass leakage Surveillance has been made. This change affects ITS 3.6.1.1 page 3.6.1.1-2 and Bases pages B 3.6.1.1-4 and B 3.6.1.1-5, the CTS markup for ITS 3.6.1.1, pages 2 of 3 and 3 of 3, the Discussion of Changes for ITS 3.6.1.1, DOC L.3 (deleted from pages 4 and 5), the ISTS markup page 3.6-2, the Justification for Deviations to ITS 3.6.1.1, JFD 2 (page 1), the ISTS Bases markup page B 3.6-4, insert page B 3.6-4 (deleted), and B 3.6-5, and the No Significant Hazards Consideration for ITS 3.6.1.1, NSHC L.3 (deleted from pages 3 and 4).

2. Markup errors have been corrected (ISTS Condition C insert modified to include "D" as indicated in TSTF-207 markups and SR 3.6.1.3.10 Frequency added the word "the"). The changes affect the ISTS 3.6.1.3 markup pages 3.6-10 and 3.6-17.

3. Markup error has been corrected (Bases Background insert word "permits" changed to "prevents"). The change affects the ISTS 3.6.1.6 Bases markup page B 3.6-38.

4. The Applicable Safety Analysis Bases has been revised to include the proper Reference. This change affects ITS 3.6.1.7 Bases pages B 3.6.1.7-2 and B 3.6.1.7-6 and the ISTS Bases markup insert pages B 3.6-43 and B 3.6-47.

5. Markup errors have been corrected (Applicable Safety Analyses Bases added "steam line" as more specific indication of the actual analysis and Applicability Bases added word "excessive" to insert). These changes affect the ISTS 3.6.1.7 Bases markup pages B 3.6-43 and B 3.6-44.

6. The Frequency for SR 3.6.2.4.2 has been changed from 5 years to 10 years, as requested by the NRC. The changes affect ITS 3.6.2.4 page 3.6.2.4-2 and Bases page B 3.6.2.4-4, the Discussion of Changes for ITS 3.6.2.4, DOC M.1 (page 2), the ISTS markup page 3.6-38, the Justification for Deviations to ITS 3.6.2.4, JFD 4 (page 1), and the ISTS Bases markup page B 3.6-74.

7. Markup error has been corrected (in Bases of SR 3.6.2.4, the word "will" has been deleted). The change affects the ISTS 3.6.2.4 Bases markup page B 3.6-73.

8. The change committed to during discussions with the NRC to resolve RAI 3.6.4.1-1 has been made. This change affects ITS 3.6.4.1 page 3.6.4.1-2 and Bases pages B 3.6.4.1-4 and B 3.6.4.1-5, the CTS markup for ITS 3.6.4.1, page 1 of 1, the Discussion of Changes for ITS 3.6.4.1, DOC M.2 (page 2), the ISTS

markup page 3.6-48, the Justification for Deviations to ITS 3.6.4.1, JFD 2 (page 1), and the ISTS Bases markup page B 3.6-100.

9. Typographical/editorial changes have been made (the SR 3.6.4.1.1 vacuum value has been changed from "0.1" to "0.10" in the typed ITS and from ".10" to "0.10" in the ISTS markup). These changes affect ITS 3.6.4.1 ITS page 3.6.4.1-2 and ISTS markup page 3.6-48.

10. Markup errors have been corrected (in Bases of SR 3.6.4.1.1, the words "between surveillances" have been crossed out and in the Bases of SR 3.6.4.1.3, the word "necessarily" has been added). These changes affect the ISTS 3.6.4.1 Bases markup pages B 3.6-100 and B 3.6-101.

11. Markup error has been corrected (in SR 3.6.4.2.1, the word "and" has been deleted). The change affects the ISTS 3.6.4.2 markup page B 3.6-53.

<u>Section 3.7</u>

1. A typographical error has been corrected (the word "in" is changed to "to"). The change affects the ISTS 3.7.2 markup insert page 3.7-7.

2. Markup error has been corrected (in the Bases of ACTION A.1, the word "MODES" has been changed to "MODE"). The change affects the ISTS 3.7.4 Bases markup page B 3.7-20.

<u>Section 3.8</u>

1. Typographical errors have been corrected (the term "SR" has been added before the second SR number in Note 1 of the Surveillance Requirements, the word "the" has been added before the word "common" in SR 3.8.1.3 Note 5, the SR number has been changed from "SR 3.8.1.7" to "SR 3.8.1.8" in the Bases for SR 3.8.1.2 and SR 3.8.1.8, and a comma is added after the word "start" in SR 3.8.1.13.a). The changes affect ITS 3.8.1 pages 3.8.1-6, 3.8.1.7, and 3.8.1-11 and Bases page 3.8.1-20, and the ISTS markup insert page 3.8-6, page 3.8-7, and page 3.8-11 and Bases pages B 3.8-17.

2. ISTS markup errors in ITS 3.8.1 have been corrected (a period has been included in SR 3.8.1.3 Note 5, , the word "level" and the appropriate period have been added to SR 3.8.1.6 Bases, deleted SR 3.8.1.11 discussion of power factor requirements to testing, and the redundant unit "V" has been deleted from SR 3.8.1.13.a). These changes affect the ISTS 3.8.1 markup pages 3.8-7 and 3.8-11 and Bases pages B 3.8-19 and B 3.8-22.

3. Markup error has been corrected (in Bases ACTION A.1, added "V" after 4160). The change affects the ISTS 3.8.2 Bases markup page B 3.8-38.

4. The word "and" has been deleted in LCO 3.8.4.a consistent with the format of the ITS. This change affects ITS 3.8.4 page 3.8.4-1 and the ISTS markup insert page 3.8-24a.

5. A change to the description of the modified performance discharge test has been made as requested by the NRC. This change affects ITS 3.8.4 page B 3.8.4-14 and the ISTS Bases markup page B 3.8-58.

6. ITS LCO 3.8.5 has been modified as requested by the NRC. In addition, a typographical error has been corrected (changed the word "buses" to "bus" and deleted the term "opposite unit"). These changes affect ITS 3.8.5 page 3.8.5-1 and Bases pages B 3.8.5-2 and B 3.8.5-3, the CTS markup for ITS 3.8.5, page 1 of 1, the Discussion of Changes for ITS 3.8.5, DOC M.1 (page 1), the ISTS markup page 3.8-28, the Justification for Deviations to ITS 3.8.5, JFD 7 (page 1), and the ISTS Bases markup page B 3.8-61.

7. ITS LCO 3.8.7 Condition C has been modified to be consistent with the LaSalle ITS. This change affects ITS 3.8.7 page 3.8.7-2 and Bases pages B 3.8.7-8 and B 3.8.7-9 and the ISTS markup insert page 3.8-38 and Bases insert page B 3.8-86.

8. Typographical errors have been corrected (revised inverted MCC numbers 1 and 2 and added the proper voltage for bus 25). These changes affect ITS 3.8.7 Bases pages B 3.8.7-2, B 3.8.7-11, and B 3.8.7-12 and the ISTS Bases markup insert pages B 3.8-79, B 3.8-88a, and B 3.8-88b.

<u>Section 3.9</u>

1. A change was made to the JFD as requested by the NRC. This change affects the Justification for Deviations to ITS 3.9.1, JFD 4 (page 1).

<u>Section 3.10</u>

1. Markup errors have been corrected (in Bases Background, reference was changed from "turbine low condenser vacuum" to "low turbine condenser vacuum" consistent with function name and Applicable Safety Analyses changed from "(Refs. 2 and 3)" to "(Ref. 2)"). These changes affect the ISTS 3.10.1 Bases markup pages B 3.10-6 and B 3.10-7.

2. A typographical error in NUREG-1433 has been corrected to be consistent with NUREG-1434 (the word "and" has been added). This change affects ITS 3.10.3 page 3.10.3-1 and the ISTS 3.10.3 markup page 3.10-9.

3. Typographical error in the Applicability Section of the Bases has been corrected (References have been changed from "Reference 3" to "References 1, 2, 3, 4, and 5"). This change affects ITS 3.10.1 Bases page B 3.10.6-3 and the ISTS Bases markup page B 3.10-31.

<u>Chapter 5.0</u>

1. The change committed to during discussions with the NRC to resolve RAI 5.0-1 has been made. The change affects ITS 5.1 page 5.1-1, the Discussion of Changes for ITS 5.1, DOC M.1 (page 1) and DOC LA.2 (page 1), the ISTS markup page 5.0-1, and the Justification for Deviations to ITS 5.1, JFD 3 (page 1) and JFD 4 (page 1).

2. A typographical error has been corrected in ITS 5.2.2.b, in the Justification for Deviations to ITS 5.2, and in the Discussion of Changes for ITS 5.3 (the reference to Specification 5.2.2.g has been changed to 5.2.2.f). In addition, the reference to 5.5.2.a in ITS 5.2 JFD 6 has been changed to 5.2.2.a. These changes affect ITS 5.2 page 5.2-2, the ISTS markup page 5.0-3, the Justification for Deviations to ITS 5.2, JFD 6 (page 1), and the Discussion of Changes for ITS 5.3, DOC A.2 (page 1).

3. A typographical error has been corrected in ITS 5.5.9 (the word "the" was added). The change affects ITS 5.5 page 5.5-9, and the ISTS markup page 5.0-15.

4. Markup errors in ITS 5.5, ITS 5.6, and ITS 5.7 have been corrected (in ITS 5.5.9, the word "testing" has been changed to "test"; in ITS 5.5.10.b.2, the word "approved" has been changed to "approval"; in ITS 5.6.1, the term "mrems" has been changed to "mrem" and the comma after the words "electronic dosimeter" has been deleted; in ITS 5.7.1, the word "continuously" has been crossed out consistent with the CTS; and in ITS 5.7.2 the words "accessible to personnel" have been added consistent with the CTS). These changes affect the ISTS 5.5 markup page 5.0-15 and the ISTS 5.7 markup page 5.0-23.

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ISTS markup page 3.6-48	ISTS markup page 3.6-48
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ISTS markup page 3.6-53	ISTS markup page 3.6-53
ISTS Bases markup page B 3.6-4 and insert page B 3.6-4	ISTS Bases markup page B 3.6-4
ISTS Bases markup page B 3.6-5	ISTS Bases markup page B 3.6-5
ISTS Bases markup page B 3.6-38	ISTS Bases markup page B 3.6-38
ISTS Bases markup page B 3.6-43 and insert page B 3.6-43	ISTS Bases markup page B 3.6-43 and insert page B 3.6-43
ISTS Bases markup page B 3.6-44	ISTS Bases markup page B 3.6-44
ISTS Bases markup page B 3.6-47	ISTS Bases markup page B 3.6-47
ISTS Bases markup pages B 3.6-73 and B 3.6-74	ISTS Bases markup pages B 3.6-73 and B 3.6-74
ISTS Bases markup page B 3.6-100	ISTS Bases markup page B 3.6-100
ISTS Bases markup page B 3.6-101	ISTS Bases markup page B 3.6-101
No Significant Hazards Consideration for ITS 3.6.1.1 pages 3 and 4	None

VOLUME 8	
SECTION 3.7	
DISCARD	**INSERT**
ISTS markup insert page 3.7-7	ISTS markup insert page 3.7-7
ISTS Bases markup page B 3.7-20	ISTS Bases markup page B 3.7-20

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SECTION 3.8	
DISCARD	**INSERT**
ITS pages 3.8.1-6 and 3.8.1-7	ITS pages 3.8.1-6 and 3.8.1-7
ITS page 3.8.1-11	ITS page 3.8.1-11
ITS page 3.8.4-1	ITS page 3.8.4-1
ITS page 3.8.5-1	ITS page 3.8.5-1
ITS page 3.8.7-2	ITS page 3.8.7-2
ITS Bases page B 3.8.1-20	ITS Bases page B 3.8.1-20
ITS Bases page B 3.8.4-14	ITS Bases page B 3.8.4-14
ITS Bases pages B 3.8.5-2 and B 3.8.5-3	ITS Bases pages B 3.8.5-2 and B 3.8.5-3
ITS Bases page B 3.8.7-2	ITS Bases page B 3.8.7-2
ITS Bases pages B 3.8.7-8 and B 3.8.7-9	ITS Bases pages B 3.8.7-8 and B 3.8.7-9
ITS Bases pages B 3.8.7-11 and B 3.8.7-12	ITS Bases pages B 3.8.7-11 and B 3.8.7-12
CTS markup for ITS 3.8.5 page 1 of 1	CTS markup for ITS 3.8.5 page 1 of 1
Discussion of Changes for ITS 3.8.5 pages 1 through 3	Discussion of Changes for ITS 3.8.5 pages 1 through 3
ISTS markup insert page 3.8-6	ISTS markup insert page 3.8-6
ISTS markup page 3.8-7	ISTS markup page 3.8-7
ISTS markup page 3.8-11	ISTS markup page 3.8-11
ISTS markup insert page 3.8-24a	ISTS markup insert page 3.8-24a
ISTS markup page 3.8-28	ISTS markup page 3.8-28
Justification for Deviations to ITS 3.8.5 page 1	Justification for Deviations to ITS 3.8.5 page 1
ISTS markup insert page 3.8-38	ISTS markup insert page 3.8-38
ISTS Bases markup page B 3.8-17	ISTS Bases markup page B 3.8-17
ISTS Bases markup page B 3.8-19	ISTS Bases markup page B 3.8-19
ISTS Bases markup page B 3.8-22	ISTS Bases markup page B 3.8-22
ISTS Bases markup page B 3.8-38	ISTS Bases markup page B 3.8-38
ISTS Bases markup page B 3.8-58	ISTS Bases markup page B 3.8-58
ISTS Bases markup page B 3.8-61	ISTS Bases markup page B 3.8-61
ISTS Bases markup insert page B 3.8-79	ISTS Bases markup insert page B 3.8-79
ISTS Bases markup insert page B 3.8-86	ISTS Bases markup insert page B 3.8-86
ISTS Bases markup insert pages B 3.8-88a and B 3.8-88b	ISTS Bases markup insert pages B 3.8-88a and B 3.8-88b

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DISCARD AND INSERT INSTRUCTIONS

VOLUME 10	
SECTIONS 3.9 AND 3.10	
DISCARD	**INSERT**
Justification for Deviations to ITS 3.9.1 page 1	Justification for Deviations to ITS 3.9.1 page 1
ITS page 3.10.3-1	ITS page 3.10.3-1
ITS Bases pages B 3.10.6-2 and B 3.10.6-3	ITS Bases pages B 3.10.6-2 and B 3.10.6-3
ISTS markup page 3.10-9	ISTS markup page 3.10-9
ISTS Bases markup pages B 3.10-6 and B 3.10-7	ISTS Bases markup pages B 3.10-6 and B 3.10-7
ISTS Bases markup page B 3.10-31	ISTS Bases markup page B 3.10-31

VOLUME 11	
CHAPTERS 4.0 AND 5.0	
DISCARD	**INSERT**
ITS page 5.1-1	ITS page 5.1-1
ITS page 5.2-2	ITS page 5.2-2
ITS page 5.5-9	ITS page 5.5-9
Discussion of Changes for ITS 5.1 pages 1 and 2	Discussion of Changes for ITS 5.1 pages 1 and 2
Discussion of Changes for ITS 5.3 page 1	Discussion of Changes for ITS 5.3 page 1
ISTS markup page 5.0-1	ISTS markup page 5.0-1
Justification for Deviations to ITS 5.1 page 1	Justification for Deviations to ITS 5.1 page 1
ISTS markup page 5.0-3	ISTS markup page 5.0-3
Justification for Deviations to ITS 5.2 page 1	Justification for Deviations to ITS 5.2 page 1
ISTS markup page 5.0-15	ISTS markup page 5.0-15
ISTS markup insert page 5.0-18	ISTS markup insert page 5.0-18
ISTS markup page 5.0-23	ISTS markup page 5.0-23

1.1 Definitions

DOSE EQUIVALENT I-131 (continued)	conversion factors used for this calculation shall be those listed in Table III of TID-14844, AEC, 1962, "Calculation of Distance Factors for Power and Test Reactor Sites;" Table E-7 of Regulatory Guide 1.109, Rev. 1, NRC, 1977; or ICRP 30, Supplement to Part 1, pages 192-212, Table titled, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity."
FUEL DESIGN LIMITING RATIO FOR CENTERLINE MELT (FDLRC)	The FDLRC shall be 1.2 times the LHGR existing at a given location divided by the product of the transient LHGR limit and the fraction of RTP.
LEAKAGE	LEAKAGE shall be:

a. Identified LEAKAGE

1. LEAKAGE into the drywell, such as that from pump seals or valve packing, that is captured and conducted to a sump or collecting tank; or

2. LEAKAGE into the drywell atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE;

b. Unidentified LEAKAGE

All LEAKAGE into the drywell that is not identified LEAKAGE;

c. Total LEAKAGE

Sum of the identified and unidentified LEAKAGE; and

d. Pressure Boundary LEAKAGE

LEAKAGE through a nonisolable fault in a Reactor Coolant System (RCS) component body, pipe wall, or vessel wall.

(continued)

1.1 Definitions

⟨1.0⟩

DOSE EQUIVALENT I-131 (continued)	conversion factors used for this calculation shall be those listed in [Table III of TID-14844, AEC, 1962, "Calculation of Distance Factors for Power and Test Reactor Sites" ~~or those listed in~~ Table E-7 of Regulatory Guide 1.109, Rev. 1, NRC, 1977, or ICRP 30, Supplement to Part 1, page 192-212, Table titled, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity"]. 1
EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME	The ECCS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ECCS initiation setpoint at the channel sensor until the ECCS equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays, where applicable. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. 2
END OF CYCLE RECIRCULATION PUMP TRIP (EOC RPT) SYSTEM RESPONSE TIME	The EOC RPT SYSTEM RESPONSE TIME shall be that time interval from initial signal generation by [the associated turbine stop valve limit switch or from when the turbine control valve hydraulic oil control oil pressure drops below the pressure switch setpoint] to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured, [except for the breaker arc suppression time, which is not measured but is validated to conform to the manufacturer's design value]. 2
ISOLATION SYSTEM RESPONSE TIME	The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation initiation setpoint at the channel sensor until the isolation valves travel to their required positions. Times shall include diesel generator starting and sequence loading delays, where applicable. The response time may be measured by means of any series of sequential, 2

(continued)

Insert 1 3

<CTS>

1.1 Definitions

<1.0>

SHUTDOWN MARGIN (SDM) (continued)

With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

STAGGERED TEST BASIS

<DOC A.14>

A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.

<1.0>

THERMAL POWER

THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

<DOC A.14>

TURBINE BYPASS SYSTEM RESPONSE TIME

The TURBINE BYPASS SYSTEM RESPONSE TIME ~~consists of two components:~~

~~a. The time from initial movement of the main turbine stop valve or control valve until 80% of the turbine bypass capacity is established; and~~

~~b. The time from initial movement of the main turbine stop valve or control valve until initial movement of the turbine bypass valve.~~

shall be that time interval from when the turbine bypass control unit generates a turbine bypass valve flow signal until the turbine bypass valves travel to their required positions.

The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.

1

1D

Although the ANFB correlation is valid at reactor steam dome pressures > 600 psia, application of the fuel cladding integrity SL at reactor steam dome pressures < 785 psig is conservative.

1

D

BASES

APPLICABLE SAFETY ANALYSES

~~2.1.1.1a Fuel Cladding Integrity [General Electric Company (GE) Fuel]~~ (continued) 1

move this paragraph below as indicated

indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER > 50 % RTP. Thus, a THERMAL POWER limit of 25% RTP for reactor pressure < 785 psig is conservative. 1

3

2.1.1.1b Fuel Cladding Integrity ~~[Advanced Nuclear Fuel Corporation (ANF) Fuel]~~ 8 1

Siemens Power Corporation

The use of the ~~XN-3~~ ANFB correlation is valid for critical power calculations at pressures > ~~580 psig~~ 600 psia and bundle mass fluxes > 0.~~25~~ .1 x 10^6 lb/hr-ft^2 (Ref. ~~3~~ 2 and 3). For operation at low pressures or low flows, the fuel cladding integrity SL is established by a limiting condition on core THERMAL POWER, with the following basis:

1

move from page B 2.0-2 and above

~~Provided that the water level in the vessel downcomer is maintained above the top of the active fuel, natural circulation is sufficient to ensure a minimum bundle flow for all fuel assemblies that have a relatively high power and potentially can approach a critical heat flux condition. For the ANF 9x9 fuel design, the minimum bundle flow is > 30 x 10^3 lb/hr. For the ANF 8x8 fuel design, the minimum bundle flow is > 28 x 10^3 lb/hr. For all designs, the coolant minimum bundle flow and maximum flow area are such that the mass flux is always > 0.25 x 10^6 lb/hr-ft^2. Full scale critical power tests taken at pressures down to 14.7 psia indicate that the fuel assembly critical power at 0.25 x 10^6 lb/hr-ft^2 is approximately 3.35 MWt. At 25% RTP, a bundle power of approximately 3.35 MWt corresponds to a bundle radial peaking factor of > 3.0, which is significantly higher than the expected peaking factor. Thus, a THERMAL POWER limit of 25% RTP for reactor pressures < 785 psig is conservative.~~

(continued)

<CTS>

ACTIONS

	CONDITION	REQUIRED ACTION		COMPLETION TIME
<3.3.C Act 2.b + 2.c> <3.3.H Act 1.b>	C. (continued)	C.2	Disarm the associated CRD.	4 hours
<3.3.C Act 1.a> <3.3.C Act 2.a.1>	D. ---------NOTE--------- Not applicable when THERMAL POWER > ~~[~~10~~]~~% RTP. 1 ---------------------- Two or more inoperable control rods not in compliance with ~~banked position withdrawal sequence (BPWS)~~ analyzed rod position sequence 2 and not separated by two or more OPERABLE control rods.	D.1 OR D.2	Restore compliance with ~~BPWS~~. Restore control rod to OPERABLE status.	4 hours 4 hours
1 4	~~E. ---------NOTE--------- Not applicable when THERMAL POWER > [10]% RTP. ---------------------- One or more groups with four or more inoperable control rods.~~	~~E.1~~	~~Restore control rod to OPERABLE status.~~	~~4 hours~~
<3.3.C Act 1.b> <3.3.C Act 1.c> <3.3.C Act 3> <3.3.C Act 4> <3.3.H Act 2> <3.3.I Act 2>	~~F~~ E 4. Required Action and associated Completion Time of Condition A, 4 C, D, ~~or E~~ or E not met. OR Nine or more control rods inoperable.	~~F~~ E 4 .1	Be in MODE 3.	12 hours

1 D

⟨CTS⟩

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
⟨4.4.A.1.b⟩	SR 3.1.7.1 Verify available volume of sodium pentaborate solution is ~~[~~within the limits of Figure 3.1.7-1~~, or ≥ [4530] gallons]~~.	24 hours 2
⟨4.4.A.1.a⟩	[SR 3.1.7.2 Verify temperature of sodium pentaborate solution is within the limits of ~~[~~Figure 3.1.7-2~~]~~. 2	24 hours] 2
⟨4.4.A.1.c⟩	[SR 3.1.7.3 Verify temperature of pump suction piping is ~~within the limits of [Figure 3.1.7-2]~~ ≥ 83°F.	24 hours 2] 2
⟨4.4.A.2.a⟩	SR 3.1.7.4 Verify continuity of explosive charge.	31 days
⟨4.4.A.2.b⟩	SR 3.1.7.5 Verify the concentration of ~~boron~~ sodium pentaborate 3 in solution is ~~[~~within the limits of Figure 3.1.7-1~~]~~. 2	31 days AND Once within 24 hours after water or ~~boron~~ sodium pentaborate is added to solution D AND Once within 24 hours after solution temperature is restored within the limits of ~~[~~Figure 3.1.7-2~~]~~ 2

(continued)

1

Insert LCO

OPERABILITY requirements for control rods also include correct assembly of the CRD housing supports.

TSTF -32

Insert A-1

the local scram reactivity rate assumptions may not be met if the stuck control rod separation criteria are not met. Therefore, a verification that the separation criteria are met must be performed immediately. The stuck control rod separation criteria are not met if: a) the stuck control rod occupies a location adjacent to two "slow" control rods, b) the stuck control rod occupies a location adjacent to one “slow” control rod, and the one “slow” control rod is also adjacent to another "slow" control rod, or c) if the stuck control rod occupies a location adjacent to one "slow" control rod when there is another pair of "slow" control rods elsewhere in the core adjacent to one another. The description of "slow" control rods is provided in LCO 3.1.4 "Control Rod Scram Times." In addition, 2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.16	-----------------NOTES----------------- 1. Neutron detectors are excluded. 2. For Function 1.a, not required to be performed when entering MODE 2 from MODE 1 until 24 hours after entering MODE 2. --------------------------------------- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.17	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.18	-----------------NOTES----------------- 1. Neutron detectors are excluded. 2. For Function 5 "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. --------------------------------------- Verify the RPS RESPONSE TIME is within limits.	24 months on a STAGGERED TEST BASIS

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 Monitors					
a. Neutron Flux – High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 121/125 divisions of full scale
	5(a)	3	H	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 121/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.17	NA
	5(a)	3	H	SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.17	NA
2. Average Power Range Monitors					
a. Neutron Flux – High, Setdown	2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.7 SR 3.3.1.1.9 SR 3.3.1.1.14 SR 3.3.1.1.17	≤ 17.1% RTP
b. Flow Biased Neutron Flux – High	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.14 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 0.58 W + 63.4% RTP and ≤ 120% RTP(b)

(continued)

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

(b) 0.58 W + 59.1% and ≤ 118.4% RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

Table 3.3.1.1-1 (page 2 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	
2. Average Power Range Monitors (continued)						
c. Fixed Neutron Flux − High	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.14 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 120% RTP	A D
d. Inop	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.17	NA	
3. Reactor Vessel Steam Dome Pressure − High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.11 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 1050 psig	A
4. Reactor Vessel Water Level − Low	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.11 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 11.8 inches	A
5. Main Steam Isolation Valve − Closure	1	8	F	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 9.8% closed	B
6. Drywell Pressure − High	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.10 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 2.43 psig	A

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.1.1 Verify ≥ 12 rods withdrawn. OR C.2.1.2 Verify by administrative methods that startup with RWM inoperable has not been performed in the last 12 months.	Immediately Immediately
	AND C.2.2 Verify movement of control rods is in compliance with the analyzed rod position sequence 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 analyzed rod position sequence by a second licensed operator or other qualified member of the technical staff.	During control rod movement

(continued)

ACTIONS

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

SURVEILLANCE REQUIREMENTS

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

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

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

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.1	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.2.1.2	-----------------NOTE------------------ Not required to be performed until 1 hour after any control rod is withdrawn at $\leq$ 10% RTP in MODE 2. --------------------------------------- Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.2.1.3	-----------------NOTE------------------ Not required to be performed until 1 hour after THERMAL POWER is $\leq$ 10% RTP in MODE 1. --------------------------------------- Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.2.1.4	-----------------NOTE------------------ Neutron detectors are excluded. --------------------------------------- Perform CHANNEL CALIBRATION.	92 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.5	-----------------NOTE------------------ Neutron detectors are excluded. --------------------------------------- Verify the RBM is not bypassed when THERMAL POWER is ≥ 30% RTP and when a peripheral control rod is not selected.	92 days
SR 3.3.2.1.6	Verify the RWM is not bypassed when THERMAL POWER is ≤ 10% RTP.	24 months
SR 3.3.2.1.7	-----------------NOTE------------------ Not required to be performed until 1 hour after reactor mode switch is in the shutdown position. --------------------------------------- Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.2.1.8	Verify control rod sequences input to the RWM are in conformance with analyzed rod position sequence.	Prior to declaring RWM OPERABLE following loading of sequence into RWM
SR 3.3.2.1.9	Verify the bypassing and position of control rods required to be bypassed in RWM by a second licensed operator or other qualified member of the technical staff.	Prior to and during the movement of control rods bypassed in RWM

Table 3.3.5.1-1 (page 1 of 4)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Core Spray System					
a. Reactor Vessel Water Level — Low Low	1,2,3, 4[a], 5[a]	4[b]	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.9	≥ -56.78 inches
b. Drywell Pressure — High	1,2,3	4[b]	B	SR 3.3.5.1.4 SR 3.3.5.1.6 SR 3.3.5.1.9	≤ 2.43 psig
c. Reactor Steam Dome Pressure — Low (Permissive)	1,2,3	2	C	SR 3.3.5.1.4 SR 3.3.5.1.6 SR 3.3.5.1.9	≥ 306 psig and ≤ 342 psig
	4[a], 5[a]	2	B	SR 3.3.5.1.4 SR 3.3.5.1.6 SR 3.3.5.1.9	≥ 306 psig and ≤ 342 psig
d. Core Spray Pump Discharge Flow — Low (Bypass)	1,2,3, 4[a], 5[a]	1 per pump	E	SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 577 gpm and ≤ 830 gpm
e. Core Spray Pump Start-Time Delay Relay	1, 2, 3 4[a], 5[a]	1 per pump	C	SR 3.3.5.1.8 SR 3.3.5.1.9	≤ 11.4 seconds
2. Low Pressure Coolant Injection (LPCI) System					
a. Reactor Vessel Water Level — Low Low	1,2,3, 4[a], 5[a]	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.9	≥ -56.78 inches
b. Drywell Pressure — High	1,2,3	4	B	SR 3.3.5.1.4 SR 3.3.5.1.6 SR 3.3.5.1.9	≤ 2.43 psig
c. Reactor Steam Dome Pressure — Low (Permissive)	1,2,3	2	C	SR 3.3.5.1.4 SR 3.3.5.1.6 SR 3.3.5.1.9	≥ 306 psig and ≤ 342 psig
	4[a], 5[a]	2	B	SR 3.3.5.1.4 SR 3.3.5.1.6 SR 3.3.5.1.9	≥ 306 psig and ≤ 342 psig

(continued)

(a) When associated ECCS subsystem(s) are required to be OPERABLE per LCO 3.5.2, "ECCS — Shutdown."

(b) Also required to initiate the associated diesel generator (DG).

Table 3.3.5.1-1 (page 2 of 4)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	
2. LPCI System (continued)						
d. Reactor Steam Dome Pressure – Low (Break Detection)	1,2,3	4	B	SR 3.3.5.1.4 SR 3.3.5.1.7 SR 3.3.5.1.9	≥ 868 psig and ≤ 891 psig	A
e. Low Pressure Coolant Injection Pump Start – Time Delay Relay Pumps B and D	1,2,3, 4[(a)], 5[(a)]	1 per pump	C	SR 3.3.5.1.8 SR 3.3.5.1.9	≤ 6.7 seconds	B D
f. Low Pressure Coolant Injection Pump Discharge Flow – Low (Bypass)	1,2,3, 4[(a)], 5[(a)]	1 per loop	E	SR 3.3.5.1.4 SR 3.3.5.1.5 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 2526 gpm	A
g. Recirculation Pump Differential Pressure–High (Break Detection)	1, 2, 3	4 per pump	C	SR 3.3.5.1.4 SR 3.3.5.1.8 SR 3.3.5.1.9	≥ 2.3 psid	A
h. Recirculation Riser Differential Pressure–High (Break Detection)	1, 2, 3	4	C	SR 3.3.5.1.4 SR 3.3.5.1.8 SR 3.3.5.1.9	≤ 2.15 psid	A
i. Recirculation Pump Differential Pressure Time Delay - Relay (Break Detection)	1, 2, 3	2	C	SR 3.3.5.1.8 SR 3.3.5.1.9	≤ 0.82 seconds	B
j. Reactor Steam Dome Pressure Time Delay - Relay (Break Detection)	1, 2, 3	2	B	SR 3.3.5.1.8 SR 3.3.5.1.9	≤ 2.26 seconds	B
k. Recirculation Riser Differential Pressure Time Delay - Relay (Break Detection)	1, 2, 3	2	C	SR 3.3.5.1.8 SR 3.3.5.1.9	≤ 0.82 seconds	B

(continued)

(a) When associated ECCS subsystem(s) are required to be OPERABLE per LCO 3.5.2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1	Isolate the mechanical vacuum pump.	12 hours
	<u>OR</u>		
	C.2	Remove the mechanical vacuum pump breaker from service.	12 hours
	<u>OR</u>		
	C.3	Isolate the main steam lines.	12 hours
	<u>OR</u>		
	C.4	Be in MODE 3.	12 hours

BASES

ACTIONS (continued)

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 during withdrawal of one or more of the first 12 control rods was not performed in the last 12 months. These requirements minimize the number of reactor startups initiated with the RWM inoperable. 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 imposed by Required Action C.2.2. Required Action C.2.2 allows for the RWM Function to be performed manually and requires a double check of compliance with the prescribed rod sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other task qualified member of the technical staff (e.g., shift technical advisor or reactor engineer). D

The RWM may be bypassed under these conditions to allow continued operations. In addition, Required Actions of LCO 3.1.3 and LCO 3.1.6 may require bypassing the RWM, during which time the RWM must be considered inoperable with Condition C entered and its Required Actions taken.

D.1

With the RWM inoperable during a reactor shutdown, the operator is still capable of enforcing the prescribed control rod sequence. Required Action D.1 allows for the RWM Function to be performed manually and requires a double check of compliance with the prescribed rod sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other task qualified member of the technical

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.5

The RBM is automatically bypassed when power is below a specified value or if a peripheral control rod is selected. The power level is determined from the APRM signals input to each RBM channel. The automatic bypass setpoint must be verified periodically to be < 30% RTP. In addition, it must also be verified that the RBM is not bypassed when a control rod that is not a peripheral control rod is selected (only one non-peripheral control rod is required to be verified). If any bypass setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the APRM channel can be placed in the conservative condition to enable the RBM. If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.8. The 92 day Frequency is based on the actual trip setpoint methodology utilized for these channels. D

SR 3.3.2.1.6

The RWM is automatically bypassed when power is above a specified value. The power level is determined from feedwater flow and steam flow signals. The automatic bypass setpoint must be verified periodically to be > 10% RTP. If the RWM low power setpoint is nonconservative, then the RWM is considered inoperable. Alternately, the low power setpoint channel can be placed in the conservative condition (nonbypass). If placed in the nonbypassed condition, the SR is met and the RWM is not considered inoperable. The Frequency is based on the trip setpoint methodology utilized for the low power setpoint channel.

SR 3.3.2.1.7

A CHANNEL FUNCTIONAL TEST is performed for the Reactor Mode Switch—Shutdown Position Function to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be C

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.d. Contaminated Condensate Storage Tank Level — Low

Low level in a CCST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valves between HPCI and the CCSTs are open and, upon receiving a HPCI initiation signal, water for HPCI injection would be taken from the CCSTs. However, if the water levels in the CCSTs fall below a preselected level, first the suppression pool suction valves automatically open, and then the CCST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the HPCI pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CCST suction valve automatically closes. The Function is implicitly assumed in the accident and transient analyses (which take credit for HPCI) since the analyses assume that the HPCI suction source is the suppression pool.

Contaminated Condensate Storage Tank Level — Low signals are initiated from four level switches (two associated with each CCST). The output from these switches are provided to the logics of both HPCI Systems. The logic is arranged such that any level switch can cause the suppression pool suction valves to open and the CCST suction valve of both units to close. The Contaminated Condensate Storage Tank Level — Low Function Allowable Value is high enough to ensure adequate pump suction head while water is being taken from either CCST.

While four channels of the Contaminated Condensate Storage Tank Level — Low Function are available, only two channels are required to be OPERABLE when HPCI is required to be OPERABLE and both CCSTs are aligned to the HPCI System. In addition, when one CCST is isolated from the unit HPCI System, the two channels required are those associated with the CCST that is aligned to HPCI. These requirements will ensure that no single instrument failure can preclude HPCI swap to suppression pool source. Refer to LCO 3.5.1 for HPCI Applicability Bases. D

(continued)

ACTIONS

C.1 and C.2 (continued)

this Condition if a channel in this Function is inoperable), since the loss of the Function was considered during the development of Reference 4 and considered acceptable for the 24 hours allowed by Required Action C.2.

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." For Required Action C.1, the Completion Time only begins upon discovery that the same feature in both subsystems (e.g., both CS subsystems) cannot be automatically initiated due to inoperable channels within the same variable as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or it would not necessarily result in a safe state for the channel in all events.

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic component initiation capability for the HPCI System. If both CCSTs are available, HPCI automatic initiation capability is lost if two required Function 3.d channels are inoperable and untripped. If one CCST is not available, automatic initiation capability is lost if two channels associated with the aligned CCST are inoperable and untripped. HPCI automatic initiation capability is lost if

(continued)

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

two Function 3.e channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCI System must be declared inoperable within 1 hour after discovery of loss of HPCI initiation capability. As noted, Required Action D.1 is only applicable if the HPCI pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

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." For Required Action D.1, the Completion Time only begins upon discovery that the HPCI System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1 or the suction source must be aligned to the suppression pool per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the HPCI System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the HPCI suction piping), Condition H must be entered and its Required Action taken.

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable, untripped channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action F.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken.

G.1 and G.2

Required Action G.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one Function 4.c channel and one Function 5.c channel are inoperable, (b) a combination of Function 4.d, 4.e, 5.d, and 5.e channels are inoperable such that channels associated with five or more low pressure ECCS pumps are inoperable, or (c) one Function 4.f channel and one Function 5.f channel are inoperable.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action G.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability.

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." For Required Action G.1, the Completion Time only begins upon discovery that the ADS cannot be automatically

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Reactor Vessel Water Level — High (continued)

The Reactor Vessel Water Level — High Allowable Value is high enough to preclude isolating the injection valve of the RCIC during normal operation, yet low enough to trip the RCIC System prior to water overflowing into the MSLs.

Two channels of Reactor Vessel Water Level — High Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

3. Contaminated Condensate Storage Tank Level — Low

Low level in a CCST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally, the suction valve between the RCIC pump and the CCST is open and, upon receiving a RCIC initiation signal, water for RCIC injection would be taken from the CCSTs. However, if the water level in the CCSTs fall below a preselected level, first the suppression pool suction valves automatically open, and then the CCST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the RCIC pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CCST suction valve automatically closes.

Two level switches are used to detect low water level in each CCST. The Contaminated Condensate Storage Tank Level — Low Function Allowable Value is set high enough to ensure adequate pump suction head while water is being taken from the CCST.

While four channels of Contaminated Condensate Storage Tank Level — Low Function are available, only two channels are required to be OPERABLE when RCIC is required to be OPERABLE and both CCSTs are aligned to the RCIC System. In addition, when one CCST is isolated from the unit RCIC System, the two channels required are those associated with the CCST that is aligned to RCIC. These requirements will ensure that no single instrument failure can preclude RCIC swap to suppression pool source. Refer to LCO 3.5.3 for RCIC Applicability Bases. D

(continued)

ACTIONS (continued)

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 1) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1) limiting the allowable out of service time, if a loss of automatic RCIC initiation capability exists, is not required. This Condition applies to the Reactor Vessel Water Level — High Function whose logic is arranged such that any inoperable channel will result in a loss of automatic RCIC initiation (high water level trip) capability. As stated above, this loss of automatic RCIC initiation (high water level trip) capability was analyzed and determined to be acceptable. This Condition also applies to the Manual Initiation Function. This is allowed since this Function is not assumed in any accident or transient analysis, thus a total loss of manual initiation capability (Required Action C.1) for 24 hours is allowed. The Required Action does not allow placing a channel in trip since this action would not necessarily result in a safe state for the channel in all events.

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in automatic initiation capability being lost for the RCIC System. In this case if both CCSTs are available RCIC automatic initiation (RCIC source swap over) capability is lost if two required Function 3 channels are inoperable and untripped. If one CCST is not available, automatic initiation capability is lost if two channels associated with the aligned CCST are inoperable and untripped. In addition, automatic initiation (RCIC source swap over) capability is lost if two Function 4 channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour from discovery of loss of RCIC initiation capability. As noted, Required Action D.1 is only applicable if the RCIC pump suction is not aligned to the suppression pool since, if aligned, the Function is already performed.

(continued)

BASES

ACTIONS

B.1 (continued)

have one channel OPERABLE or in trip. For Function 4.c this would require two or more channels to be OPERABLE or in trip in the trip system.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1. The applicable Condition specified in Table 3.3.6.1-1 is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A or B and the associated Completion Time has expired, Condition C will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

D.1, D.2.1, and D.2.2

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time the associated MSLs may be isolated (Required Action D.1), and, if allowed (i.e., plant safety analysis allows operation with an MSL isolated), operation with that MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. This Required Action will generally only be used if a Function 1.d channel is inoperable and untripped. The associated MSL(s) to be isolated are those whose Main Steam Line Flow—High Function channel(s) are inoperable. Alternately, 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 (Required Actions D.2.1 and D.2.2). The Completion Times

(continued)

B 3.3 INSTRUMENTATION

B 3.3.7.2 Mechanical Vacuum Pump Trip Instrumentation

BASES

BACKGROUND

The Mechanical Vacuum Pump Trip Instrumentation initiates a trip of the main condenser mechanical vacuum pump breaker following events in which main steam line radiation exceeds predetermined values. Tripping the mechanical vacuum pump limits the offsite and control room doses in the event of a control rod drop accident (CRDA).

The Mechanical Vacuum Pump Trip Instrumentation (Refs. 1 and 2) includes detectors, monitors, and relays that are necessary to cause initiation of a mechanical vacuum pump trip. The channels include electronic equipment that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an isolation signal to the mechanical vacuum pump trip logic.

The trip logic consists of two independent trip systems, with two channels of Main Steam Line Radiation — High in each trip system. Each trip system is a one-out-of-two logic for this Function. Thus, either channel of Main Steam Line Radiation — High in each trip system is needed to trip a trip system. The outputs of the channels in a trip system are combined in a one-out-of-two taken twice logic so that both trip systems must trip to result in a pump trip signal. | 0

APPLICABLE SAFETY ANALYSES

The Mechanical Vacuum Pump Trip Instrumentation is assumed in the safety analysis for the CRDA. The Mechanical Vacuum Pump Trip Instrumentation initiates a trip of the mechanical vacuum pump to limit offsite and control room doses resulting from fuel cladding failure in a CRDA (Ref. 3)

The mechanical vacuum pump trip instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES

ACTIONS (continued)

C.1, C.2, C.3, and C.4

With any Required Action and associated Completion Time not met, the plant must be brought to a MODE or other specified 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 (Required Action C.4). Alternately, the mechanical vacuum pump may be removed from service since this performs the intended function of the instrumentation (Required Actions C.1 and C.2). An additional option is provided to isolate the main steam lines (Required Action C.3), which may allow operation to continue. Isolating the main steam lines effectively provides an equivalent level of protection by precluding fission product transport to the condenser.

The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions, or to remove the mechanical vacuum pump from service, or to isolate the main steam lines, in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

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 the associated Conditions and Required Actions may be delayed for up to 6 hours provided mechanical vacuum pump trip capability is maintained. 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. 4) 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 mechanical vacuum pump will trip when necessary.

SR 3.3.7.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.2.3 and SR 3.3.7.2.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. A Note to SR 3.3.7.2.3 states that radiation detectors are excluded from CHANNEL CALIBRATION since they are calibrated in accordance with SR 3.3.7.2.4.

The Frequency of SR 3.3.7.2.3 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift associated with the channel, except for the radiation detectors, in the setpoint analysis. The Frequency of SR 3.3.7.2.4 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift for the radiation detector in the setpoint analysis.

SR 3.3.7.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the mechanical vacuum pump breaker is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a breaker or the isolation valve is incapable of operating, the associated instrument channel(s) would be inoperable.

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

(continued)

TECHNICAL CHANGES - MORE RESTRICTIVE

M.3 (cont'd) determined Operable (by performing a CHANNEL FUNCTIONAL TEST) within 1 hour after withdrawal of any control rod when RTP is $\leq$ 10%, not just when the withdrawal is for the purpose of making the reactor critical. This change is necessary to ensure the safety analysis assumptions concerning control rod worth are maintained by ensuring the RWM is Operable during any potential change in control rod worth. This is an additional restriction on plant operation.

M.4 With the RWM inoperable, the CTS 3.3.L Action allows control rod movement to continue provided a second licensed operator or other qualified member of the technical staff verifies control rod movement is in compliance with the prescribed control rod sequence. In ITS 3.3.2.1, with the RWM inoperable during a reactor startup, continued movement of control rods will only be allowed if $\geq$ 12 control rods are withdrawn (ITS 3.3.2.1 Required Action C.2.1.1) or if a startup with RWM inoperable has not been performed in the last 12 months (ITS 3.3.2.1 Required Action C.2.1.2). These new requirements are being added to ensure the RWM is reliable. These changes are additional restrictions on plant operation.

M.5 A new RWM Surveillance has been added (proposed SR 3.3.2.1.6) to verify the automatic enabling point of the RWM. This SR ensures that the RWM is not inadvertently bypassed with power level $\leq$ 10% RTP. This is an additional restriction on plant operation to ensure proper operation of the RWM.

M.6 A new RWM Surveillance has been added (proposed SR 3.3.2.1.9) to verify the bypassing and position of control rods required to be bypassed (taken out of service) in RWM by a second licensed operator or other qualified member of the technical staff. When a control rod is taken out of service in the RWM, if the control rod is fully inserted, the RWM provides an insert and withdraw block to the control rod. If the control rod is not fully inserted, the RWM provides only a withdraw block to the control rod. This is required prior to and during the movement of control rods bypassed in RWM. This is an additional restriction on plant operation to ensure proper operation of the RWM.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 CTS Table 3.2.E-1 Note (a) states that the RBM shall be automatically bypassed when a peripheral control rod is selected. This system design detail is proposed to be relocated to the UFSAR. This design detail is not necessary to be included in the Technical Specifications to ensure the OPERABILITY of the RBM

<CTS>

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

<3.1.A>
<2.2.A>

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

<Appl 3.1.A>
<T 3.1.A-1>
<Appl 2.2.A>

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

-----NOTE-----

1. Separate Condition entry is allowed for each channel.

2. When Functions 2.b and 2.c channels are inoperable due to APRM indication not within limits, entry into associated Conditions and Required Actions may be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power, and for up to 12 hours if the APRM is indicating a higher power value than the calculated power.

5

<T 4.1.A-1 footnote d>

CONDITION	REQUIRED ACTION	COMPLETION TIME
<3.1.A Act 1> <3.1.A Act 2> <3.1.A Act 2.c> <2.2.A Action> A. One or more required channels inoperable.	A.1 Place channel in trip. OR A.2 Place associated trip system in trip.	12 hours 12 hours
<3.1.A Act 2> <3.1.A Act 2.b> <2.2.A Action> B. One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. OR B.2 Place one trip system in trip.	6 hours 6 hours
<3.1.A Act 2> <3.1.A Act 2.a> <3.1.A Act 3> <2.2.A Action> C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour

(continued)

<CTS> <Insert from page 3.3-6> 17

SURVEILLANCE REQUIREMENTS (continued)

<T 4.1.A-1 footnote a> <T 4.1.A-1 footnote o> <T 4.1.A-1>

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.10 4 6 3	-------------------NOTES------------------- 1. Neutron detectors are excluded. 2. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until ~~12~~ 24 hours after entering MODE 2. 2 3. For Function 2.b, not required for the flow portion of the channels. --- Perform CHANNEL CALIBRATION. 5	184 days
<T 4.1.A-1> SR 3.3.1.1.10 5 5	Perform CHANNEL FUNCTIONAL TEST.	~~[18]~~ 24 months 1
<T 4.1.A-1 footnote a> <T 4.1.A-1 footnote h> <T 4.1.A-1 footnote o> <T 4.1.A-1> SR 3.3.1.1.10 6	-------------------NOTES------------------- 1. Neutron detectors are excluded. 2. For Function 1.a, not required to be performed when entering MODE 2 from MODE 1 until ~~12~~ 24 hours after entering MODE 2. 14 2 --- Perform CHANNEL CALIBRATION.	~~[18]~~ 24 months 1
~~SR 3.3.1.1.14~~	~~Verify the APRM Flow Biased Simulated Thermal Power—High time constant is ≤ [7] seconds.~~	~~[18] months~~ 6
<4.1.A.2> SR 3.3.1.1.15 7 6	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~[18]~~ 24 months 1

(continued)

L ⟨CTS⟩ ⟨move to page 33-5 as indicated⟩ 17

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
⟨DOC M.3⟩ SR 3.3.1.1.~~16~~ 13	Verify Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ [30]% RTP. 45 1	~~[18] months~~ 72 days 1
⟨DOC L.1⟩ ⟨DOC A.7⟩ ⟨4.1.A.3⟩ SR 3.3.1.1.~~17~~ 18 6	-----------------NOTES----------------- 1. Neutron detectors are excluded. 2. For Function 5 "n" equals 4 channels for the purpose of determining ~~the~~ the STAGGERED TEST BASIS Frequency. 14 --------------------------------------- Verify the RPS RESPONSE TIME is within limits.	24 1 ~~[18]~~ months on a STAGGERED TEST BASIS

1 D

⟨CTS⟩
⟨T 3.1.A-1⟩
⟨T 4.1.A-1⟩
⟨T 2.2.A-1⟩

TSTF-264 changes not adopted [16]

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 Monitors [14]					SR 3.3.1.1.5 [3]
a. Neutron Flux — High	2	~~3~~ [1]	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 16 [6] SR 3.3.1.1.15 17	≤ ~~120~~ 121/125 divisions of full scale [1] [5] [A]
	5(a)	~~3~~ [1]	H	SR 3.3.1.1.1 [3] SR 3.3.1.1.5 4 SR 3.3.1.1.13 16 SR 3.3.1.1.15 17 [6]	≤ ~~120~~ 121/125 divisions of full scale [1] [5] [A]
b. Inop	2	~~3~~ [1]	G	SR 3.3.1.1.4 SR 3.3.1.1.15 17 [6]	NA
	5(a)	~~3~~ [1]	H	SR 3.3.1.1.5 4 [3] SR 3.3.1.1.15 17 [6] 1 [14]	NA
2. Average Power Range Monitors					
a. Neutron Flux — High, Setdown	2	~~2~~ [1]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.7 [3] SR 3.3.1.1.8 9 SR 3.3.1.1.11 14 [5] SR 3.3.1.1.16 17 [6]	≤ ~~20~~ 17.1% RTP [A]
b. Flow Biased ~~Simulated Thermal Power~~ Neutron Flux — High	1	~~2~~ [1]	F	[1] 120 SR 3.3.1.1.1 [3] SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.8 9 SR 3.3.1.1.9 10 SR 3.3.1.1.11 14 [5] ~~SR 3.3.1.1.14~~ add SR 3.3.1.1.16 [6] SR 3.3.1.1.16 17 SR 3.3.1.1.17 18 [6]	≤ ~~0.58~~ W [1] + ~~62~~ 63.4% RTP and ≤ ~~115.5~~% RTP(b) [3] [A] [D]

(continued)

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

(b) ~~0.58~~ W + ~~60~~% 59.1 ~~0.58 AW~~ RTP and ≤ 118.4 % RTP [1] when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating." [1] [A]

<CTS>
<T 3.1.A-1>
<T 4.1.A-1>
<T 2.2.A-1>

Table 3.3.1.1-1 (page 2 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
2. Average Power Range Monitors (continued)		1		SR 3.3.1.1.5 3	3
c. Fixed Neutron Flux — High	1	~~[2]~~	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.~~8~~ 9 SR 3.3.1.1.~~9~~ 10 SR 3.3.1.1.~~11~~ 14 SR 3.3.1.1.~~15~~ 17 SR 3.3.1.1.~~17~~ 18 3 5 6	≤ ~~[~~120~~]~~% RTP 1 D A
~~d. Downscale~~ 7	~~1~~	~~[2]~~	~~F~~	~~SR 3.3.1.1.8~~ ~~SR 3.3.1.1.9~~ ~~SR 3.3.1.1.15~~	~~≥ [3]% RTP~~ 7
~~e.~~ d. Inop 7	1,2	~~[2]~~	G	SR 3.3.1.1.~~8~~ 9 SR 3.3.1.1.~~9~~ 10 SR 3.3.1.1.~~15~~ 17 6	NA 3
3. Reactor Vessel Steam Dome Pressure — High	1,2	~~[2]~~	G	SR 3.3.1.1.1 SR 3.3.1.1.~~9~~ 10 1 ~~SR 3.3.1.1.10~~ 11 SR 3.3.1.1.~~13~~ 16 5 SR 3.3.1.1.~~15~~ 17 3 SR 3.3.1.1.~~17~~ 18 6	≤ ~~[1054]~~ 1050 psig 3 1 A
4. Reactor Vessel Water Level — Low~~, Level 3~~	1,2	~~[2]~~	G	SR 3.3.1.1.1 SR 3.3.1.1.~~9~~ 10 ~~SR 3.3.1.1.10~~ 11 1 SR 3.3.1.1.~~13~~ 16 5 SR 3.3.1.1.~~15~~ 17 6 SR 3.3.1.1.~~17~~ 18	≥ ~~[10]~~ 11.8 inches 10 3
5. Main Steam Isolation Valve — Closure	1	~~[8]~~	F	SR 3.3.1.1.9 SR 3.3.1.1.~~13~~ 16 SR 3.3.1.1.~~15~~ 17 5 SR 3.3.1.1.~~17~~ 18 6	≤ ~~[10]~~ 9.8% closed 1 B
6. Drywell Pressure — High	1,2	~~[2]~~	G	8 ~~SR 3.3.1.1.1~~ SR 3.3.1.1.~~9~~ 10 ~~SR 3.3.1.1.10~~ 7 ~~SR 3.3.1.1.13~~ add SR 3.3.1.1.12 5 5 SR 3.3.1.1.~~15~~ 17 6 SR 3.3.1.1.18 13	≤ ~~[1.92]~~ 2.43 psig 3 1 A

(continued)

<CTS>

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued) <3.3.L Action> <DOC M.4>	C.2.1.1 Verify ≥ 12 rods withdrawn. OR C.2.1.2 Verify by administrative methods that startup with RWM inoperable has not been performed in the last ~~calendar year~~ 12 months. AND C.2.2 Verify movement of control rods is in compliance with ~~banked position withdrawal sequence (BPWS)~~ the analyzed rod position sequence by a second licensed operator or other qualified member of the technical staff.	Immediately Immediately During control rod movement
D. RWM inoperable during reactor shutdown. <3.3.L Action>	D.1 Verify movement of control rods is in ~~accordance~~ compliance with ~~BPWS~~ analyzed rod position sequence by a second licensed operator or other qualified member of the technical staff.	During control rod movement

(continued)

7 1 2 D

L <CTS>

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE		FREQUENCY	
<4.3.L.2> <DOC L.2> <DOC M.3>	SR 3.3.2.1.2	------NOTE------ Not required to be performed until 1 hour after any control rod is withdrawn at ≤ [10]% RTP in MODE 2. ------------ Perform CHANNEL FUNCTIONAL TEST.	[92] days	3
5 <T 4.2.E-1> <4.3.L.3> <DOC L.2> Insert SR 3.3.2.1.4 from page 3.3-19	SR 3.3.2.1.3	------NOTE------ Not required to be performed until 1 hour after THERMAL POWER is ≤ [10]% RTP in MODE 1. ------------ Perform CHANNEL FUNCTIONAL TEST.	[92] days	3
<DOC M.5> <T 4.2.E-1 footnote a>	SR 3.3.2.1.~~4~~ 5 5	~~------NOTE------ Neutron detectors are excluded. ------------~~ Verify the RBM~~s~~ 4 is not bypassed when THERMAL POWER is ≥ 30% RTP and when a peripheral control rod is not selected. ~~a. Low Power Range—Upscale Function is not bypassed when THERMAL POWER is ≥ 29% and ≤ 64% RTP.~~ ~~b. Intermediate Power Range—Upscale Function is not bypassed when THERMAL POWER is > 64% and ≤ 84% RTP.~~ ~~c. High Power Range—Upscale Function is not bypassed when THERMAL POWER is > 84% RTP.~~ 4	92 days ~~[18] months~~	3 D
<DOC M.5>	SR 3.3.2.1.~~5~~ 6 5	Verify the RWM is not bypassed when THERMAL POWER is ≤ [10]% RTP.	~~18~~ 24 months	3

(continued)

<CTS>

<T 3.2.E-1>
<T 4.2.E-1>
<3.3.L>
<3.3.M>

Table 3.3.2.1-1 (page 1 of 1)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Rod Block Monitor				
a. ~~Low Power Range -~~ Upscale	(a)	~~[2]~~	SR 3.3.2.1.1 SR 3.3.2.1.~~4~~ 5 SR 3.3.2.1.~~7~~ 4	~~≤ [115.5/125] divisions of full scale~~ As specified in the COLR
~~b. Intermediate Power Range — Upscale~~	~~(b)~~	~~[2]~~	~~SR 3.3.2.1.1~~ ~~SR 3.3.2.1.4~~ ~~SR 3.3.2.1.7~~	~~≤ [109.7/125] divisions of full scale~~
~~c. High Power Range — Upscale~~	~~(c),(d)~~	~~[2]~~	~~SR 3.3.2.1.1~~ ~~SR 3.3.2.1.4~~ ~~SR 3.3.2.1.7~~	~~≤ [105.9/125] divisions of full scale~~
~~d.~~ b. Inop	~~(d),(e)~~ (a)	~~[2]~~	SR 3.3.2.1.1 SR 3.3.2.1.5	NA
~~e.~~ c. Downscale	~~(d),(e)~~ (a)	~~[2]~~	SR 3.3.2.1.1 SR 3.3.2.1.~~7~~ 4	≥ ~~[93/125] divisions of full scale~~ 3.8% RTP
~~f. Bypass Time Delay~~	~~(d),(e)~~	~~[2]~~	~~SR 3.3.2.1.1~~ ~~SR 3.3.2.1.7~~	~~≤ [2.0] seconds~~
2. Rod Worth Minimizer	1~~(f)~~ (b), 2~~(f)~~ (b)	~~[1]~~	SR 3.3.2.1.2 SR 3.3.2.1.3 SR 3.3.2.1.~~5~~ 6 SR 3.3.2.1.8 SR 3.3.2.1.9	NA
<DOC M.1> 3. Reactor Mode Switch — Shutdown Position	~~(g)~~ (c)	~~[2]~~	SR 3.3.2.1.~~6~~ 7	NA

(a) THERMAL POWER ≥ ~~[29]~~ 30% ~~and ≤ [64]% RTP and MCPR < 1.70.~~ RTP and no peripheral control rod selected

~~(b) THERMAL POWER > [64]% and ≤ [84]% RTP and MCPR < 1.70.~~

~~(c) THERMAL POWER > [84]% and < 90% RTP and MCPR < 1.70.~~

~~(d) THERMAL POWER ≥ 90% RTP and MCPR < 1.40.~~

~~(e) THERMAL POWER ≥ [64]% and < 90% RTP and MCPR < 1.70.~~

~~(f)~~ (b) With THERMAL POWER ≤ ~~[10]~~ 10% RTP.

~~(g)~~ (c) Reactor mode switch in the shutdown position.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1433, REVISION 1
ITS: 3.3.2.1 - CONTROL ROD BLOCK INSTRUMENTATION

1. The proper Quad Cities 1 and 2 plant specific nomenclature/value/design requirements have been provided.

2. Editorial change made to be consistent with Required Action C.2.2.

3. The brackets have been removed and the proper plant specific information/value has been provided.

4. ISTS SR 3.3.2.1.4 and ISTS Table 3.3.2.1-1, Note (a) have been modified and ISTS Table 3.3.2.1-1, Functions 1.b, 1.c, and 1.f, including Notes (b), (c), (d), and (e) have been deleted to be consistent with the Quad Cities 1 and 2 RBM design. The RBM design in the ISTS is based on a "Post-ARTS" RBM design. Quad Cities 1 and 2 has not installed the "ARTS" RBM modification. In addition, the requirements have been renumbered, where applicable, to reflect the deletions.

5. ISTS SR 3.3.2.1.7 has been renumbered as SR 3.3.2.1.4 and the bracketed Frequency has been changed from 18 months to 92 days consistent with the current licensing basis. The Surveillances have been reordered and renumbered as required.

6. A new Surveillance (ITS 3.3.2.1.9) has been added to the ITS 3.3.2.1 consistent with the current and proposed requirements in the LaSalle Unit 1 and 2 Technical Specifications. This change was added for consistency between ComEd Boiling Water Reactor Technical Specifications.

7. Required Action C.2.1.2 has been modified to be consistent with the Bases. | D

<u>INSERT FUNCTION 1.e</u>

e. Core Spray Pump Start-Time Delay Relay	1, 2, 3, 4[a], 5[a]	1 per pump	C	SR 3.3.5.1.8 SR 3.3.5.1.9	$\leq$ 11.4 seconds	B D

<CTS>

<T 3.2.B-1>
<T 4.2.B-1>
<DOC M.1>

Table 3.3.5.1-1 (page 2 of 6)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. LPCI System (continued)					
b. Drywell Pressure – High	1,2,3	~~[4]~~ (b) 6	B	~~SR 3.3.5.1.1~~ SR 3.3.5.1.2 4 ~~[SR 3.3.5.1.3]~~ 5 ~~SR 3.3.5.1.5~~ SR 3.3.5.1.6 7 SR 3.3.5.1.6 9 ~~SR 3.3.5.1.7~~ 4	≤ ~~[1.92]~~ 2.43 psig] 3
c. Reactor Steam Dome Pressure – Low (Injection Permissive) 6	1,2,3	~~[4]~~ 2	7 C	~~SR 3.3.5.1.1~~ 6 SR 3.3.5.1.2 4 ~~[SR 3.3.5.1.3]~~ SR 3.3.5.1.6 ~~SR 3.3.5.1.5~~ 7 SR 3.3.5.1.6 9 5 ~~SR 3.3.5.1.7~~ 4	≥ ~~[390]~~ 306 psig and ≤ ~~[500]~~ 342 psig 3
	$4^{(a)}$, $5^{(a)}$	~~[4]~~ 2	7 B	~~SR 3.3.5.1.1~~ 6 SR 3.3.5.1.2 4 ~~[SR 3.3.5.1.3]~~ SR 3.3.5.1.6 ~~SR 3.3.5.1.5~~ 7 SR 3.3.5.1.6 9 5 ~~SR 3.3.5.1.7~~ 4	≥ ~~[390]~~ 306 psig and ≤ ~~[500]~~ 342 psig 3
d. Reactor Steam Dome Pressure – Low ~~(Recirculation Discharge Valve Permissive)~~ 6 (Break Detection) 6	6 1,2,3 ~~$1^{(c)}$, $2^{(c)}$, $3^{(c)}$~~	[4]	~~C~~ 6 B	~~SR 3.3.5.1.1~~ SR 3.3.5.1.2 4 ~~[SR 3.3.5.1.3]~~ 7 SR 3.3.5.1.6 7 SR 3.3.5.1.6 9 5	≥ ~~[335]~~ psig ≥ 868 psig and ≤ 891 psig
~~e. Reactor Vessel Shroud Level – Level 0~~ 11	~~1,2,3~~	~~[2]~~	~~B~~	~~SR 3.3.5.1.1~~ ~~SR 3.3.5.1.2~~ ~~[SR 3.3.5.1.3]~~ ~~SR 3.3.5.1.5~~ ~~SR 3.3.5.1.6~~	~~≥ [-202] inches~~
~~f.~~ e. Low Pressure Coolant Injection Pump Start – Time Delay Relay	1,2,3, $4^{(a)}$, $5^{(a)}$	~~[4]~~ 1 per pump	C	SR 3.3.5.1.5 8 SR 3.3.5.1.6 9 5	3
Pumps ~~A~~, B, D and					≥ 9 seconds and ≤ ~~[]~~ 6.7 seconds 9
~~Pump~~ C 6					≤ 1 second 6

(continued)

(a) When associated ECCS ~~subsystem(s)~~ are required to be OPERABLE per LCO 3.5.2. 8

~~(b) Also required to initiate the associated [DG and isolate the associated PSW T/B isolation valves].~~ 6

~~(c) With associated recirculation pump discharge valve open.~~ 6

Insert Functions 2g, 2.h, 2.i, 2.j and 2.k [1]

<CTS>
<T 3.2.B-1>
<T 4.2.B-1>
<Doc M.1>

Table 3.3.5.1-1 (page 3 of 6)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. LPCI System (continued) [3]					
f ~~g.~~ Low Pressure Coolant Injection Pump Discharge Flow — Low (Bypass)	1,2,3, $4^{(a)}$, $5^{(a)}$	~~(4)~~ ~~[1]~~ 1 per ~~pump~~ loop [3]	E	~~SR 3.3.5.1.1~~ SR 3.3.5.1.5 [7] SR 3.3.5.1.~~2~~ 4 [5] SR 3.3.5.1.~~5~~ 8 SR 3.3.5.1.~~6~~ 9 [5]	≥ ~~[ ]~~ 2526 gpm [3] ~~and ≤ [ ] gpm~~ [3]
~~h. Manual Initiation~~ [2]	~~1,2,3, $4^{(a)}$, $5^{(a)}$~~	~~[2] [1 per subsystem]~~	~~C~~	~~SR 3.3.5.1.6~~	~~NA~~
3. High Pressure Coolant Injection (HPCI) System					
a. Reactor Vessel Water Level — Low Low, ~~Level 2~~ [6]	1, $2^{(~~b~~ c)}$, $3^{(~~b~~ c)}$ [6]	~~[4]~~	B	SR 3.3.5.1.1 SR 3.3.5.1.2 ~~SR 3.3.5.1.3~~ SR 3.3.5.1.3 [5] ~~SR 3.3.5.1.5~~ SR 3.3.5.1.~~6~~ 9 [5] ~~SR 3.3.5.1.7~~ [4]	≥ ~~[-47]~~ -56.78 inches [3]
b. Drywell Pressure — High	1, $2^{(~~b~~ c)}$, $3^{(~~b~~ c)}$ [6]	~~[4]~~	B	~~SR 3.3.5.1.1~~ SR 3.3.5.1.6 [7] SR 3.3.5.1.~~2~~ 4 ~~SR 3.3.5.1.3~~ [5] ~~SR 3.3.5.1.5~~ SR 3.3.5.1.~~6~~ 9 ~~SR 3.3.5.1.7~~ [4]	≤ ~~[1.92]~~ 2.43 psig [3]
c. Reactor Vessel Water Level — High ~~Level 8~~ [6]	1, $2^{(~~b~~ c)}$, $3^{(~~b~~ c)}$ [6]	~~[2]~~	C	~~SR 3.3.5.1.1~~ SR 3.3.5.1.2 ~~SR 3.3.5.1.3~~ SR 3.3.5.1.3 [5] ~~SR 3.3.5.1.5~~ SR 3.3.5.1.~~6~~ 9 [5] ~~SR 3.3.5.1.7~~ [4]	≤ ~~[56.5]~~ 54.23 inches [3]
d. Contaminated [6] Condensate Storage Tank (CCST) [6] Level — Low	1, $2^{(~~b~~ c)}$, $3^{(~~b~~ c)}$ [6]	~~[2]~~	D	~~SR 3.3.5.1.1~~ [7] SR 3.3.5.1.~~2~~ 4 ~~SR~~ 3.3.5.1.~~5~~ 8 SR 3.3.5.1.~~6~~ 9 [5]	≥ ~~[0] inches~~ 598 ft 1 inch
e. Suppression Pool Water Level — High	1, $2^{(~~b~~ c)}$, $3^{(~~b~~ c)}$	~~[2]~~	D	~~SR 3.3.5.1.1~~ SR 3.3.5.1.~~2~~ 4 ~~SR 3.3.5.1.3~~ [7] SR 3.3.5.1.~~5~~ 8 SR 3.3.5.1.~~6~~ 9 [5]	≤ ~~[154]~~ ~~inches~~ 15 ft 11.25 inches [3]

(continued)

(a) When ~~the~~ [7] associated ECCS [8] subsystem(s) are required to be OPERABLE per LCO 3.5.2 [8].

(~~b~~ c) [6] With reactor steam dome pressure > ~~[150]~~ psig. [3]

<CTS>

<T.3.2.B-1>
<T4.2.B-1>

Table 3.3.5.1-1 (page 4 of 6)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. HPCI System (continued)		3			
f. High Pressure Coolant Injection Pump Discharge Flow — Low (Bypass)	1, 2(c), 3(c) 6	~~(1)~~	E	7 5 ~~SR 3.3.5.1.1~~ SR 3.3.5.1.2 4 SR 3.3.5.1.5 6 SR 3.3.5.1.6 9 5	≥ 634 gpm and ≤ [ ] gpm 3 7
g. Manual Initiation	1, 2(c), 3(c)	~~(1)~~	C	SR 3.3.5.1.6 9 5	NA
4. Automatic Depressurization System (ADS) Trip System A					
a. Reactor Vessel Water Level — Low Low ~~Low, Level 1~~	1, 2(c), 3(c) 6	~~(2)~~	F 5	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.3 ~~SR 3.3.5.1.3~~ ~~SR 3.3.5.1.5~~ SR 3.3.5.1.6 9 5	≥ ~~[-113]~~ -56.78 inches 3
b. Drywell Pressure — High	1, 2(c), 3(c)	~~(2)~~	F 7	~~SR 3.3.5.1.1~~ SR 3.3.5.1.2 4 ~~SR 3.3.5.1.3~~ 5 SR3.3.5.1.6 ~~SR 3.3.5.1.5~~ SR 3.3.5.1.6 9	≤ ~~[1.92]~~ 2.43 psig 3
c. Automatic Depressurization System Initiation Timer	1, 2(c), 3(c) 6	~~(1)~~	G	~~[SR 3.3.5.1.3]~~ 8 SR 3.3.5.1.6 9 5	≤ ~~[120]~~ 119 seconds 3
~~d. Reactor Vessel Water Level — Low, Level 3 (Confirmatory)~~	~~1, 2(d), 3(d)~~	~~[1]~~	~~F~~	~~SR 3.3.5.1.1 SR 3.3.5.1.2 [SR 3.3.5.1.3] SR 3.3.5.1.5 SR 3.3.5.1.6~~ 5	~~≥ [10] inches~~ 10
10 d ~~e.~~ Core Spray Pump Discharge Pressure — High	1, 2(c), 3(c) 6	~~(2)~~	G	~~SR 3.3.5.1.1~~ 4 SR 3.3.5.1.2 ~~SR 3.3.5.1.3~~ SR3.3.5.1.6 7 ~~SR 3.3.5.1.5~~ SR 3.3.5.1.6 9 5	≥ 101.9 psig and ≤ 148.1 psig 3

(continued)

(c) With reactor steam dome pressure > ~~[150]~~ psig. 6 3

<CTS>

<T 3.2.D-1>
<T 4.2.D-1>

Table 3.3.5.2-1 (page 1 of 1)
Reactor Core Isolation Cooling System Instrumentation

FUNCTION	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level — Low Low, ~~Level 2~~ 6	~~4~~ 1	B	SR 3.3.5.2.1 SR 3.3.5.2.2 ~~SR 3.3.5.2.3~~ 3 SR 3.3.5.2.3 ~~SR 3.3.5.2.5~~ 4 SR 3.3.5.2.6	≥ ~~-47~~ -56.78 1 inches
2. Reactor Vessel Water Level — High, ~~Level 8~~ 6	~~2~~	C 2	SR 3.3.5.2.1 SR 3.3.5.2.2 ~~SR 3.3.5.2.3~~ 3 SR 3.3.5.2.3 ~~SR 3.3.5.2.5~~ 4 SR 3.3.5.2.6	≤ ~~56.5~~ 54.23 inches
3. contaminated 6 Condensate Storage Tank (CCST) 6 Level — Low	~~2~~	D	5 ~~SR 3.3.5.2.1~~ SR 3.3.5.2.2 4 2 ~~SR 3.3.5.2.3~~ 3 ~~SR 3.3.5.2.5~~ 5 1 SR 3.3.5.2.6	≥ ~~[illegible] inches~~ 598 ft 1 inch 2
~~4. Suppression Pool Water Level — High~~	~~2~~	D	5 ~~SR 3.3.5.2.1~~ SR 3.3.5.2.2 4 2 ~~SR 3.3.5.2.3~~ 3 SR 3.3.5.2.5 SR 3.3.5.2.6	≤ ~~151 inches~~ 15 ft 11.25 inches 1 ~~1~~
~~5. Manual Initiation~~	~~1~~	C	SR 3.3.5.2.6	NA 1

A B D B A

⟨CTS⟩

⟨T 3.2.A-1⟩
⟨T 4.2.A-1⟩

Table 3.3.6.1-1 (page 5 of 6)
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)					
[i. RCIC Equipment Room Temperature — High (Turbine Area)	1,2,3	[1] 2	F	[SR 3.3.6.1.1] SR 3.3.6.1.2 [SR 3.3.6.1.3] SR 3.3.6.1.4 (6) SR 3.3.6.1.7	≤ [ ] 169 °F]
[j. RCIC Equipment Room Differential Temperature — High	1,2,3	[1]	F	[SR 3.3.6.1.1] SR 3.3.6.1.2 [SR 3.3.6.1.3] SR 3.3.6.1.4 SR 3.3.6.1.7	≤ [ ]°F]
[k. Manual Initiation	1,2,3	[1 per group]	G	SR 3.3.6.1.7	NA]
5. Reactor Water Cleanup (RWCU) System Isolation					
a. Differential Flow — High	1,2,3	[1]	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.6 SR 3.3.6.1.7 SR 3.3.6.1.8	≤ [79] gpm
b. Area Temperature — High	1,2,3	[3] [1 per room]	F	SR 3.3.6.1.1 SR 3.3.6.1.2 [SR 3.3.6.1.3] SR 3.3.6.1.6 SR 3.3.6.1.7 [SR 3.3.6.1.8]	≤ [150]°F
c. Area Ventilation Differential Temperature — High	1,2,3	[3] [1 per room]	F	SR 3.3.6.1.1 SR 3.3.6.1.2 [SR 3.3.6.1.3] SR 3.3.6.1.6 SR 3.3.6.1.7 [SR 3.3.6.1.8]	≤ [67]°F
d. (a) SLC System Initiation	1,2	[2](b) (1)	(I) (H)	SR 3.3.6.1.7	NA
e. (b) 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 3.3.6.1.3] SR 3.3.6.1.6 SR 3.3.6.1.7 [SR 3.3.6.1.8]	≥ [-47] 11.8 inches
[f. Manual Initiation	1,2,3	[1 per group]	G	SR 3.3.6.1.7	NA]

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

(continued)

<CTS> 1 Insert ITS 3.3.7.2 (Page 2 of 3)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1	Isolate the mechanical vacuum pump.	12 hours
	OR		
<3.2.L Action>	C.2	Remove the mechanical vacuum pump breaker from service.	12 hours
	OR		
	C.3	Isolate the main steam lines.	12 hours
	OR		
	C.4	Be in MODE 3.	12 hours

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Reactor Vessel Steam Dome Pressure—High (continued)

Vessel Steam Dome Pressure—High Function initiates a scram for transients that results in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference ~~4~~ 2 [3], reactor ~~scram~~ (the analyses conservatively assume scram on the Average Power Range Monitor Fixed Neutron Flux—High signal, [2] or the Main Steam Isolation Valve—Closure not the Reactor Vessel Steam Dome Pressure—High signal), along with the ~~SRVs~~ S safety valves [3], limits the peak RPV pressure to less than the ASME Section III Code limits. D

High reactor pressure signals are initiated from four pressure transmitters that sense reactor pressure. The Reactor Vessel Steam Dome Pressure—High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

Four channels of Reactor Vessel Steam Dome Pressure—High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 when the RCS is pressurized and the potential for pressure increase exists.

4. Reactor Vessel Water Level—Low, Level 3 [7]

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at ~~Level 3~~ this level [7] to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level—Low, Level 3 Function is assumed in the analysis of the recirculation line break (Ref. ~~6~~ 8 [3]) and is credited in the loss of normal feedwater flow event (Ref. 9) [3]. The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the Emergency Core Cooling Systems (ECCS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level—Low, ~~Level 3~~ [7] signals are initiated from four ~~level~~ differential pressure [3] transmitters that sense the difference between the pressure due to a constant column of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.3 (continued)

converter

accurately reflects the required setpoint as a function of flow. Each flow signal from the respective flow ~~unit~~ must be ≤ 105% of the calibrated flow signal. If the flow ~~unit~~ signal is not within the limit, ~~one~~ required APRM that receives an input from the inoperable flow ~~unit~~ must be declared inoperable. 3

100 all s converter

The Frequency of 7 days is based on engineering judgment, operating experience, and the reliability of this instrumentation.

TSTF-205

Insert SR 3.3.1.1.4

SR 3.3.1.1.4 and SR 3.3.1.1.8 6

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the ~~entire~~ channel will perform the intended function. 2 2

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 and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within ~~12~~ 24 hours after entering MODE 2 from MODE 1. ~~Twelve~~ Twenty four hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR. 7

7

Insert SR 3.3.1.1.8-1

A Frequency of 7 days for SR 3.3.1.1.4 7 provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. ~~9~~ 13).

Insert SR 3.3.1.1.5 7

~~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. A Frequency of 7 days provides an acceptable level of system average availability over the~~

TSTF-205 not shown

(continued)

B 3.3 INSTRUMENTATION

B 3.3.2.1 Control Rod Block Instrumentation

BASES

BACKGROUND

Control rods provide the primary means for control of reactivity changes. Control rod block instrumentation includes channel sensors, logic circuitry, switches, and relays that are designed to ensure that specified fuel design limits are not exceeded for postulated transients and accidents. During high power operation, the rod block monitor (RBM) provides protection for control rod withdrawal error events. During low power operations, control rod blocks from the rod worth minimizer (RWM) enforce specific control rod sequences designed to mitigate the consequences of the control rod drop accident (CRDA). During shutdown conditions, control rod blocks from the Reactor Mode Switch—Shutdown Position Function ensure that all control rods remain inserted to prevent inadvertent criticalities.

1

The purpose of the RBM is to limit control rod withdrawal if localized neutron flux exceeds a predetermined setpoint during control rod manipulations (Ref. 1). ~~It is assumed to function~~ to block further control rod withdrawal to preclude a MCPR Safety Limit (SL) violation. The RBM supplies a trip signal to the Reactor Manual Control System (RMCS) to appropriately inhibit control rod withdrawal during power operation above the ~~low power range~~ 30% RTP setpoint when a non-peripheral control rod is selected 1. The RBM has two channels, either of which can initiate a control rod block when the channel output exceeds the control rod block setpoint. One RBM channel inputs into one RMCS rod block circuit and the other RBM channel inputs into the second RMCS rod block circuit. The RBM channel signal is generated by averaging a set of local power range monitor (LPRM) signals ~~at various core heights surrounding the control rod being withdrawn. A signal from one average power range monitor (APRM) channel assigned to each Reactor Protection System (RPS) trip system supplies a reference signal for the RBM channel in the same trip system. This reference signal is used to determine which RBM range setpoint (low, intermediate, or high) is enabled. If the APRM is indicating less than the low power range setpoint, the RBM is automatically bypassed. The RBM is also automatically bypassed if a peripheral control rod is selected (Ref. 1).~~ 1

Insert BKGRND 1

D

(continued)

BASES

ACTIONS

A.1 (continued)

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.

2 These requirements minimize the number of reactor startups initiated with the RWM inoperable.

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 (4 during withdrawal of one or more of the first 12 control rods) 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 imposed by Required Action C.2.2. Required Action C.2.2 allows for the RWM Function to be performed manually and requires a double check of compliance with the prescribed rod sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other (task 1) qualified member of the technical staff (e.g., shift technical advisor or reactor engineer) 2.

D

(continued)

BASES

The Note to SR 3.3.2.1.2 [2]

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.2 and SR 3.3.2.1.3 (continued)

[1] and by attempting to select a control rod not in compliance with the prescribed sequence and verifying a selection error occurs

the prescribed sequence and verifying a control rod block occurs. As noted in the SRs, SR 3.3.2.1.2 is not required to be performed until 1 hour after any control rod is withdrawn in MODE 2 , and [2]. ~~As noted,~~ SR 3.3.2.1.3 is not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. ~~This~~ allows entry into MODE 2 ~~for SR 3.3.2.1.2, and entry into MODE 1 when THERMAL POWER is ≤ 10% RTP for SR 3.3.2.1.3~~ on a startup and entry into MODE 2 concurrent with a power reduction to ≤ 10% RTP during a shutdown to perform the required Surveillance if the 92 day Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. ~~The Frequencies are based on reliability analysis (Ref. 8).~~

at ≤ 10% RTP [4]

Insert SR 3.3.2.1.2 [1]

[6] Insert from page B 3.3-53 and B 3.3-54

SR 3.3.2.1.~~4~~ 5 [6]

Insert SR 3.3.2.1.5 [1]

~~The RBM setpoints are automatically varied as a function of power. Three Allowable Values are specified in Table 3.3.2.1-1, each within a specific power range. The power at which the control rod block Allowable Values automatically change are based on the APRM signal's input to each RBM channel. Below the minimum power setpoint, the RBM is automatically bypassed. These power Allowable Values must be verified periodically to be less than or equal to the specified values.~~ If any ~~power range~~ bypass setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the ~~power range~~ APRM channel can be placed in the conservative condition ~~(i.e., enabling the proper RBM setpoint)~~ to enable the RBM. [1] If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.8. The ~~18 month~~ 92 day [6] Frequency is based on the actual trip setpoint methodology utilized for these channels.

SR 3.3.2.1.~~5~~ 6 [6]

The RWM is automatically bypassed when power is above a specified value. The power level is determined from feedwater flow and steam flow signals. The automatic bypass

(continued)

The Note to SR 3.3.2.1.3 allows a THERMAL POWER reduction to ≤ 10% RTP in MODE 1 to perform the required Surveillances if the 92 day Frequency is not met per SR 3.0.2. [2]

LCO (continued)

redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of passive valve or via system boundary status. If a normally active PCIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for closed and deactivated valves ~~in this state~~ is not required to be OPERABLE.

3

The following list is a discussion of the specified instrument Functions listed in Table 3.3.3.1-1. ~~in the accompanying LCO. These discussions are intended as examples of what should be provided for each Function when the plant specific list is prepared.~~

4

6

1. Reactor ~~Steam Dome~~ Vessel Pressure

1

Reactor ~~steam dome~~ vessel pressure is a Type A and Category I variable provided to support monitoring of Reactor Coolant System (RCS) integrity and to verify operation of the Emergency Core Cooling Systems (ECCS). Two independent pressure transmitters and indicator with a range of 0 psig to 1500 psig monitor pressure and provide pressure indication to the control room. The output from one of these channels is recorded on an independent pen recorder and the other channel output is directed to an indicator. The ~~W~~ide range recorder~~s~~ ~~are the primary indications~~ used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

1

1

1 D

2. Reactor Vessel Water Level

Reactor vessel water level is a Type A and Category I variable provided to support monitoring of core cooling and to verify operation of the ECCS. Two different range ~~The wide range water level~~ , wide range and narrow range, channels provide the PAM Reactor Vessel Water Level Function. The wide range water level channels measure from approximately 202 inches above the top of active fuel to approximately 198 inches below the top of active fuel while the narrow range channels measure from approximately 82 inches above the top of active fuel to approximately 202 inches above the top of active fuel ~~17 inches below the dryer skirt down to a point just below the bottom of the active fuel~~. Wide range water level is measured by two independent differential pressure transmitters. The output from one of these channels is recorded on an ~~two~~ independent pen recorder ~~s, which is~~ and the other output is directed to an indicator. Narrow range level is measured by two independent differential pressure transmitters. The output from these channels is directed to two independent indicators. These instruments are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

5

1

(continued)

All changes are [2] unless otherwise indicated

BASES

BACKGROUND

High Pressure Coolant Injection System (continued)

connected to relays whose contacts are arranged in a one-out-of-two taken twice logic for each Function.

The logic can also be initiated by use of a Manual Initiation push button.

The HPCI pump discharge flow is monitored by a ~~flow transmitter~~ differential pressure switch. When the pump is running and discharge flow is low enough so that pump overheating may occur, the minimum flow return line valve is opened. ~~The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the accident analysis.~~

The HPCI full flow test line isolation valves (which ~~is~~ are also a PCIV) ~~is~~ closed upon receipt of a HPCI initiation signal to allow the full system flow assumed in the accident analysis ~~and maintain primary containment isolated in the event HPCI is not operating.~~

The HPCI System also monitors the water levels in the two unit condensate storage tanks (CSTs) and the contaminated suppression pool because these are the two types of sources of water for HPCI operation. Reactor grade water in the CST is the normal source. The HPCI System is normally aligned to both CCSTs. Upon receipt of a HPCI initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless both suppression pool pump suction valves are open. If the water level in ~~the~~ any CST falls below a preselected level, first the suppression pool suction valves automatically open, and then when the valves are fully open the CST suction valve automatically closes. Two level switches are used to detect low water level in ~~the~~ any CST. ~~Either~~ each switch can cause the suppression pool suction valves to open and the CST suction valve to close. The suppression pool suction valves also automatically open and the CST suction valve closes if high water level is detected in the suppression pool (one out of two logic). To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The outputs for these switches are provided to logics of HPCI in both Unit 1 and Unit 2

The HPCI provides makeup water to the reactor until the reactor vessel water level reaches the Reactor Vessel Water Level—High ~~Level 8~~ trip, at which time the HPCI turbine trips, which causes the turbine's stop valve and the ~~injection~~ pump discharge valves to close. The logic is two-out-of-two to provide high reliability of the HPCI System. The HPCI

(continued)

The LPCI Pump Discharge Flow - Low (Bypass) Function is only required to be OPERABLE for opening since LPCI minimum flow valves are assumed to remain open during the transients and accidents analyzed in References 1, 2, and 3.

All changes are [2] unless otherwise indicated

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 2.c. Reactor Steam Dome Pressure—Low (Injection Permissive) (continued) [4]

LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

1.d, 2.e f [4] Core Spray and Low Pressure Coolant Injection Pump Discharge Flow—Low (Bypass)

The minimum flow instruments are provided to protect the associated low pressure ECCS pump from overheating when the pump is operating and the associated injection valve is not ~~fully~~ sufficiently open. The minimum flow line valve is opened when low flow is sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump. The ~~LPCI and~~ CS Pump Discharge Flow—Low (Bypass) [5] Function~~s~~ ~~are~~ is assumed to be OPERABLE and capable of closing the minimum flow valves to ensure that the ~~low pressure ECCS~~ CS flow~~s~~ assumed during the transients and accidents analyzed in References 1, 2, and 3 ~~are~~ is met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One flow transmitter per ~~E~~CS pump and one flow transmitter per LPCI subsystem are ~~is~~ used to detect the associated subsystems' flow rates. The logic is arranged such that each transmitter causes its associated minimum flow valve to open when flow is low with the pump running. The logic will close the minimum flow valve once the closure setpoint is exceeded. The LPCI minimum flow valves are time delayed such that the valves will not open for 10 seconds after the switches detect low flow. The time delay is provided to limit reactor vessel inventory loss during the startup of the RHR shutdown cooling mode. The Pump Discharge Flow—Low (Bypass) [5] Allowable Values are high enough to ensure that the pump flow rate is sufficient to protect the pumps ~~yet~~. The Core Spray Discharge Flow - Low (Bypass) Allowable Value is also low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core.

Each channel of Pump Discharge Flow—Low (Bypass) Function (two CS channels and ~~four~~ two LPCI channels) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE to ensure that no single instrument failure can preclude the ECCS function. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems. For LPCI, the closure of the minimum flow valves is not credited.

(continued)

<move to page B 3.3-112> 4
as indicated

All changes are 2 unless otherwise indicated

BASES

4

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.e. Reactor Vessel Shroud Level—Level 0 (continued)

opened for are not required to be OPERABLE in MODES 4 and 5 and are normally not used).

1.e. 4

e Core Spray and
2.f. Low Pressure Coolant Injection Pump Start—Time Delay Relay

16c

The purpose of this time delay is to stagger the start of CS and ~~the~~ LPCI pumps that are in each of Divisions 1 and 2, thus limiting the starting transients on the 4.16 kV ~~emergency~~ ESS buses. This Function is only necessary when power is being supplied from the standby power sources (DG). ~~However, since the time delay does not degrade ECCS operation, it remains in the pump start logic at all times.~~ The CS and LPCI Pump Start—Time Delay Relays are assumed to be OPERABLE in the accident and transient analyses requiring ECCS initiation. That is, the analyses assume that the pumps will initiate when required and excess loading will not cause failure of the power sources.

4

There are two CS Pump Start-Time Delay Relays and two ~~four~~ LPCI Pump Start—Time Delay Relays, one for each CS pump and one ~~in each of the RHR pump start logic circuits~~ for LPCI pump B and D. While each time delay relay is dedicated to a single pump start logic, a single failure of a LPCI Pump Start—Time Delay Relay could result in the failure of the three ~~two~~ low pressure ECCS pumps, powered from ~~on~~ the same ESS ~~ESF~~ bus, to perform their intended function ~~within the assumed ECCS RESPONSE TIME~~ (e.g., as in the case where both ECCS pumps on one ESS ~~ESF~~ bus start simultaneously due to an inoperable time delay relay). This still leaves three ~~four~~ of the six low pressure ECCS pumps OPERABLE; thus, the single failure criterion is met (i.e., loss of one instrument does not preclude ECCS initiation). 5 The Allowable Value for the CS and LPCI Pump Start—Time Delay Relays are ~~is~~ chosen to be long enough so that most of the starting transient of the first pump is complete before starting the second pump on the same 4.16 kV emergency bus and short enough so that ECCS operation is not degraded. D

Each CS and LPCI Pump Start—Time Delay Relay Function is required to be OPERABLE only when the associated LPCI subsystem is required to be OPERABLE. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the CS and LPCI subsystems.

← Insert Functions 2.g, 2.h, 2.i, and 2.k

(continued)

All changes are [2] unless otherwise indicated

BASES

Contaminated

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.d. Condensate Storage Tank Level—Low

Low level in the CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valves between HPCI and the CST are open and, upon receiving a HPCI initiation signal, water for HPCI injection would be taken from the CST. However, if the water level in the CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the HPCI pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CST suction valve automatically closes. The Function is implicitly assumed in the accident and transient analyses (which take credit for HPCI) since the analyses assume that the HPCI suction source is the suppression pool.

Contaminated [4]

Condensate Storage Tank Level—Low signals are initiated from two level switches. The logic is arranged such that either level switch can cause the suppression pool suction valves to open and the CST suction valve to close. The Condensate Storage Tank Level—Low Function Allowable Value is high enough to ensure adequate pump suction head while water is being taken from the CST.

four [4]

(two associated with each CCST)

any

The output from these switches are provided to the logics of both HPCI Systems

of both units [2]

Contaminated [4]

While four

either

Two channels of the Condensate Storage Tank Level—Low Function are required to be OPERABLE only when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI swap to suppression pool source. Refer to LCO 3.5.1 for HPCI Applicability Bases.

are available, only two channels

and both CCSTs are aligned to the HPCI System. In addition, when one CCST is isolated from the unit HPCI System, the two channels required are those associated with the CCST that is aligned to HPCI. These requirements will

D

3.e. Suppression Pool Water Level—High

Excessively high suppression pool water could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through the safety relief valves. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCI from the CST to the suppression pool to eliminate the possibility of HPCI continuing to provide additional water from a source outside containment. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CST suction valve automatically closes.

[2] C [4] D

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.a, 5.a. Reactor Vessel Water Level—Low Low Low, Level 1 (continued)

4

in Reference 2. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

differential pressure switches

2

Reactor Vessel Water Level—Low Low Low, Level 1 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 Reactor Vessel Water Level—Low Low Low, Level 1 Function are required to be OPERABLE only when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. Two channels input to ADS trip system A, while the other two channels input to ADS trip system B. Refer to LCO 3.5.1 for ADS Applicability Bases. 1△ 4

The Reactor Vessel Water Level—Low Low Low, Level 1 Allowable Value is chosen to allow time for the low pressure core flooding systems to initiate and provide adequate cooling. 4

4.b, 5.b. Drywell Pressure—High

High pressure in the drywell could indicate a break in the RCPB. Therefore, ADS receives one of the signals necessary for initiation from this Function in order to minimize the possibility of fuel damage. The Drywell Pressure—High is assumed to be OPERABLE and capable of initiating the ADS during the accidents analyzed in Reference 2. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

switches

Drywell Pressure—High signals are initiated from four pressure ~~transmitters~~ that sense drywell pressure. The Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment. 2

Four channels of Drywell Pressure—High Function are only required to be OPERABLE when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. Two channels input to ADS trip system A, while

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

acceptable because it minimizes risk while allowing time for restoration of channels.

2

4

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or it would not necessarily result in a safe state for the channel in all events.

D

2

If both CCSTs are available, HPCI automatic initiation capability is lost if two required Function 3.d channels are inoperable and untripped. If one CCST is not available, automatic initiation capability is lost if two channels associated with the aligned CCST are inoperable and untripped

HPCI

2

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic component initiation capability for the HPCI System. Automatic ~~component~~ initiation capability is lost if ~~two Function 3.d channels or~~ two Function 3.e channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCI System must be declared inoperable within 1 hour after discovery of loss of HPCI initiation capability. As noted, Required Action D.1 is only applicable if the HPCI pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

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." For Required Action D.1, the Completion Time only begins upon discovery that the HPCI System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

low pressure ECCS pumps being concurrently declared inoperable.

In this situation (loss of redundant automatic initiation capability), the 7 day allowance of Required Action E.2 is not appropriate and the subsystem associated with each inoperable channel must be declared inoperable within 1 hour. As noted (Note 1 to Required Action E.1), Required Action E.1 is only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of initiation capability for 7 days (as allowed by Required Action E.2) is allowed during MODES 4 and 5. A Note is also provided (Note 2 to Required Action E.1) to delineate that Required Action E.1 is only applicable to low pressure ECCS Functions. Required Action E.1 is not applicable to HPCI Function 3.f since the loss of one channel results in a loss of the Function (one-out-of-one logic). This loss was considered during the development of Reference 4 8 and considered acceptable for the 7 days allowed by Required Action E.2. 2

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."

1 For Required Action E.1, the Completion Time only begins upon discovery that a redundant feature in the same system (e.g., both CS subsystems) cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

If the instrumentation that controls the pump minimum flow valve is inoperable, such that the valve will not automatically open, extended pump operation with no injection path available could lead to pump overheating and failure. If there were a failure of the instrumentation, such that the Core Spray 2 valve would not automatically close, a portion of the pump flow could be diverted from the reactor vessel injection path, causing insufficient core cooling. The low pressure coolant injection minimum flow valve is assumed to remain open during injection. These

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

Function 4.~~a~~ f channel~~s~~ and one ~~or more~~ Function 5.~~a~~ f channel~~s~~ are inoperable. [2] [4]

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action G.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability. ~~The Note to Required Action G.1 states that Required Action G.1 is only applicable for Functions 4.c, 4.e, 4.f, 4.g, 5.c, 5.e, 5.f, and 5.g. Required Action G.1 is not applicable to Functions 4.h and 5.h (which also require entry into this Condition if a channel in these Functions is inoperable), since they are the Manual Initiation Functions and are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 96 hours or 8 days (as allowed by Required Action G.2) is allowed.~~ [4]

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." For Required Action G.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. ~~5~~ 4) to permit restoration of any inoperable channel to OPERABLE status if both HPCI and RCIC are OPERABLE (Required Action G.2). If either HPCI or RCIC is inoperable, the time shortens to 96 hours. If the status of HPCI or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCI or RCIC inoperability. However, the total time for an inoperable channel cannot exceed 8 days. If the status of HPCI or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the [2]

(continued)

2

These requirements will

Contaminated 5

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

C 5

3. Condensate Storage Tank Level—Low (continued)

each 5

Two level switches are used to detect low water level in the CST. The Condensate Storage Tank Level—Low Function Allowable Value is set high enough to ensure adequate pump suction head while water is being taken from the CST. C 5

2 While four

Contaminated 5

5 only two channels

Two channels of Condensate Storage Tank Level—Low Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC swap to suppression pool source. Refer to LCO 3.5.3 for RCIC Applicability Bases.

and both CCSTs are aligned to the RCIC system. In addition, when one CCST is isolated from the unit RCIC System, the two channels required are those associated with the CCST that is aligned to RCIC.

D

4. Suppression Pool Water Level—High

2

Excessively high suppression pool water level could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through the ~~safety/~~relief valves. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of RCIC from the CST to the suppression pool to eliminate the possibility of RCIC continuing to provide additional water from a source outside primary containment. This Function satisfies Criterion 3 of ~~the NRC Policy Statement~~. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CST suction valve automatically closes. C C 5 C

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

Suppression pool water level signals are initiated from two level switches. The Allowable Value for the Suppression Pool Water Level—High Function is set low enough to ensure that RCIC will be aligned to take suction from the suppression pool before the water level reaches the point at which suppression design loads would be exceeded.

Two channels of Suppression Pool Water Level—High Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC swap to suppression pool source. Refer to LCO 3.5.3 for RCIC Applicability Bases.

2

The Allowable Value is confirmed by performance of a CHANNEL FUNCTIONAL TEST. This is acceptable since the design layout of the installation ensures the switches will trip at a level lower than the Allowable Value.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition E must be entered and its Required Action taken.

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 1) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1) limiting the allowable out of service time, if a loss of automatic RCIC initiation capability exists, is not required. This Condition applies to the Reactor Vessel Water Level—High, Level 8 Function (high water level trip) whose logic is arranged such that any inoperable channel will result in a loss of automatic RCIC initiation capability. As stated above, this loss of automatic RCIC initiation capability was analyzed and determined to be acceptable. This Condition also applies to the Manual Initiation Function. Since this Function is not assumed in any accident or transient analysis, thus a total loss of manual initiation capability (Required Action C.1) for 24 hours is allowed. The Required Action does not allow placing a channel in trip since this action would not necessarily result in a safe state for the channel in all events.

1

This is allowed

5

2

In this case if both CCSTs are available RCIC automatic initiation (RCIC source swapover) capability is lost if two required Function 3 channels are inoperable and untripped, If one CCST is not available, automatic initiation capability is lost if two channels associated with the aligned CCST are inoperable and untripped.

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in automatic component initiation capability being lost for the feature(s). For Required Action D.1 the RCIC System is the only associated feature. In this case, automatic initiation (RCIC source swapover) capability is lost if ~~two Function 3 channels or~~ two Function 4 channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not

In addition

D

2

(continued)

All changes are 1 unless otherwise indicated

BASES

BACKGROUND

3, 4. High Pressure Coolant Injection System Isolation and Reactor Core Isolation Cooling System Isolation (continued)

HPCI and RCIC Functions isolate the Group ~~3,~~ 4 ~~8~~ and ~~9~~ 5 valves as appropriate 2.

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.~~ Insert BKGD-6 The ~~Differential Flow—High and~~ SLC System Initiation Function~~s~~ receive~~s~~ input from ~~two channels, with each channel in one trip system using a one-out-of-one logic. 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.~~ Insert BKGD-7 Each of the two trip systems is connected to one of the two ~~valves on each~~ RWCU ~~penetration~~.

RWCU Functions isolate the Group ~~5~~ 3 valves.

6. Residual Heat Removal (RHR) Shutdown Cooling (SDC) 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.~~ Insert BKGD-8 The Reactor Vessel Pressure—High Function receives input from two channels, both of which provide input to both trip systems. Any channel will ~~trip~~ trip both trip systems. This is ~~with each channel in one trip system using~~ a one-out-of-~~one~~ two logic for each trip system. Each of the two trip systems is connected to one of the two valves on ~~each shutdown cooling~~ the RHR SDC suction penetration. 1 D

Shutdown Cooling System Isolation Functions isolate ~~the~~ some Group ~~1~~ 2 valves (RHR SDC suction isolation valves).

BASES

ACTIONS

B.1 (continued)

risk while allowing time for restoration or tripping of channels.

C.1

[2]

This Required Action will generally only be used if a Function 1.d, channel is inoperable and untripped. The associated MSL(s) to be isolated are those whose Main Steam Line Flow - High Function channel(s) are inoperable. Alternately,

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1. The applicable Condition specified in Table 3.3.6.1-1 is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A or B and the associated Completion Time has expired, Condition C will be entered for that channel and provides for transfer to the appropriate subsequent Condition. 1D

D.1, D.2.1, and D.2.2

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 3 within 12 hours and in MODE 4 within 36 hours (Required Actions D.2.1 and D.2.2). ~~Alternately,~~ the associated MSLs may be isolated (Required Action D.1), and, if allowed (i.e., plant safety analysis allows operation with an MSL isolated), operation with that MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. [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~~ 8 hours. [4]

(continued)

All changes are 3 unless otherwise indicated

BASES

ACTIONS

B.1 and B.2 (continued)

conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an ~~initiation~~ isolation), Condition D must be entered and its Required Action taken.

1

C.1 and C.2

Because of the diversity of sensors available to provide ~~initiation~~ isolation signals and the redundancy of the ~~MCREC~~ CREV System instrumentation design, an allowable out of service time of ~~6~~ 12 hours ~~is provided~~ has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function is still maintaining ~~MCREC~~ CREV System ~~initiation~~ isolation capability. A Function is considered to be maintaining ~~MCREC~~ CREV System ~~initiation~~ isolation capability when sufficient channels are OPERABLE or in trip such that ~~one~~ both trip systems will generate an initiation signal from the given Function on a valid signal. For Functions ~~4~~ 1 and ~~5~~ 2, this would require ~~one~~ both trip systems to have one channel OPERABLE or in trip. In this situation (loss of ~~MCREC~~ CREV System ~~initiation~~ isolation capability), the ~~6~~ 12 hour allowance of Required Action C.2 is not appropriate. If the Function is not maintaining ~~MCREC~~ CREV System ~~initiation~~ isolation capability, the ~~MCREC~~ CREV System must be declared inoperable within 1 hour of discovery of the loss of ~~MCREC~~ CREV System ~~initiation~~ isolation capability in both trip systems.

Insert C.1 and C.2 — 2

2

The 1 hour Completion Time ~~(C.1)~~ is acceptable because it minimizes risk while allowing time for restoring or tripping of channels. If it is not desired to declare the CREV System inoperable, Condition D may be entered and Required Action D.1 or D.2, as applicable, taken.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action C.2. Placing the inoperable channel in trip performs the intended function of the channel ~~(starts both MCREC subsystems in the pressurization mode)~~ conservatively compensates for the inoperability, restores capability to accomodate a single failure, and allows operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where ~~it is not desired to start the subsystem~~ placing the inoperable channel in trip would result in an isolation), Condition D must be entered and its Required Action taken. 1 △

(continued)

B 3.3 INSTRUMENTATION

B 3.3.7.2 Mechanical Vacuum Pump Trip Instrumentation

BASES

BACKGROUND	The Mechanical Vacuum Pump Trip Instrumentation initiates a trip of the main condenser mechanical vacuum pump breaker following events in which main steam line radiation exceeds predetermined values. Tripping the mechanical vacuum pump limits the offsite and control room doses in the event of a control rod drop accident (CRDA). The Mechanical Vacuum Pump Trip Instrumentation (Refs. 1 and 2) includes detectors, monitors, and relays that are necessary to cause initiation of a mechanical vacuum pump trip. The channels include electronic equipment that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an isolation signal to the mechanical vacuum pump trip logic. The trip logic consists of two independent trip systems, with two channels of Main Steam Line Radiation—High in each trip system. Each trip system is a one-out-of-two logic for this Function. Thus, either channel of Main Steam Line Radiation—High in each trip system is needed to trip a trip system. The outputs of the channels in a trip system are combined in a one-out-of-two taken twice logic so that both trip systems must trip to result in a pump trip signal. 1 D
APPLICABLE SAFETY ANALYSES	The Mechanical Vacuum Pump Trip Instrumentation is assumed in the safety analysis for the CRDA. The Mechanical Vacuum Pump Trip Instrumentation initiates a trip of the mechanical vacuum pump to limit offsite and control room doses resulting from fuel cladding failure in a CRDA (Ref. 3) The mechanical vacuum pump trip instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES

ACTIONS (continued)

C.1, C.2, C.3, and C.4

With any Required Action and associated Completion Time not met, the plant must be brought to a MODE or other specified 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 (Required Action C.4). Alternately, the mechanical vacuum pump may be removed from service since this performs the intended function of the instrumentation (Required Actions C.1 and C.2). An additional option is provided to isolate the main steam lines (Required Action C.3), which may allow operation to continue. Isolating the main steam lines effectively provides an equivalent level of protection by precluding fission product transport to the condenser. D

The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions, or to remove the mechanical vacuum pump from service, or to isolate the main steam lines, in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

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 the associated Conditions and Required Actions may be delayed for up to 6 hours provided mechanical vacuum pump trip capability is maintained. 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. 4) 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 mechanical vacuum pump will trip when necessary.

SR 3.3.7.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.2.3 and SR 3.3.7.2.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. A Note to SR 3.3.7.2.3 states that radiation detectors are excluded from CHANNEL CALIBRATION since they are calibrated in accordance with SR 3.3.7.2.4.

The Frequency of SR 3.3.7.2.3 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift associated with the channel, except for the radiation detectors, in the setpoint analysis. The Frequency of SR 3.3.7.2.4 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift for the radiation detector in the setpoint analysis.

SR 3.3.7.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the mechanical vacuum pump breaker is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a breaker or the isolation valve is incapable of operating, the associated instrument channel(s) would be inoperable. D

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

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Verify source of unidentified LEAKAGE increase is not intergranular stress corrosion cracking susceptible material.	4 hours
C. Required Action and associated Completion Time of Condition A or B not met. OR Pressure boundary LEAKAGE exists.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

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

BASES

SURVEILLANCE REQUIREMENTS

3.4.2.1 (continued)

the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow patterns are established by plotting historical data as discussed in Reference 2.

Flow from a jet pump may be used to simulate the flow in the other jet pump with the same riser. This allowance may be used for two jet pumps, except that the two jet pumps may not be both of the calibrated jet pumps in the same recirculation loop. This allowance is necessary since one jet pump flow indication instrument line in Unit 1 has failed. An analysis has been performed which demonstrated the acceptability of this method (Refs. 4 and 5). D D

The 24 hour Frequency has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop OPERABILITY verification.

This SR is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

Note 2 allows this SR not to be performed until 24 hours after THERMAL POWER exceeds 25% RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data. The 24 hours is an acceptable time to establish conditions appropriate to perform this SR.

REFERENCES

1. UFSAR, Section 6.3.

(continued)

BASES

REFERENCES (continued)

2. GE Service Information Letter No. 330, including Supplement 1, "Jet Pump Beam Cracks," June 9, 1980.

3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

4. EAS 07-0289, Revision 1, "Safety Evaluation to Justify Operation With Loss of Jet Pump Flow Indication for Quad Cities 1 and 2," March 1989.

5. NRC SER supporting Quad Cities 1 and 2 Amendments 124 and 121, respectively, May 23, 1990.

D

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety and Relief Valves

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of safety valves are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB). Each unit is designed with nine safety valves, one of which also functions in the relief mode. This valve is a dual function Target Rock safety/relief valve (S/RV).

The safety valves and S/RV are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The safety valves actuate in the safety mode (or spring mode of operation). In this mode, the safety valve opens when the inlet steam pressure reaches the lift set pressure. At that point, the vertical upward force generated by the inlet pressure under the valve disc balances the downward force generated by the spring. Slight steam leakage develops across the valve disc-to-seat interface and is directed into the huddle chamber. Pressure builds up rapidly in the huddle chamber developing an additional vertical lifting force on the disc and disc holder. This additional force in conjunction with the expansive characteristic of steam causes the valve to "pop" open to almost full lift. This satisfies the Code requirement. The S/RV is a dual function Target Rock valve that can actuate by either of two modes: the safety mode or the relief mode. In the safety mode (or spring mode of operation), the S/RV opens in the same manner as described above for the safety valves. In the relief mode (or power actuated mode of operation), automatic or manual switch actuation energizes a solenoid valve which pneumatically actuates a plunger located within the main valve body. Actuation of the plunger allows pressure to be vented from the top of the main valve piston. This allows reactor pressure to lift the main valve piston, which opens the main valve. The relief valves and S/RV discharge steam through a discharge line to a point below the minimum water level in the suppression pool. All other safety valves discharge directly to the drywell.

(continued)

BASES (continued)

ACTIONS

A.1

With RCS unidentified or total LEAKAGE greater than the limits, actions must be taken to reduce the leak. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours is allowed to reduce the LEAKAGE rates before the reactor must be shut down. If an unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE; however, the total LEAKAGE limit would remain unchanged.

B.1 and B.2

An unidentified LEAKAGE increase of > 2 gpm within a 24 hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated. Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be determined not to be the source of the LEAKAGE increase within the required Completion Time. For an unidentified LEAKAGE increase greater than required limits, an alternative to reducing LEAKAGE increase to within limits (i.e., reducing the LEAKAGE rate such that the current rate is less than the "2 gpm increase in the previous 24 hours" limit; either by isolating the source or other possible methods) is to verify the source of the unidentified leakage increase is not material susceptible to IGSCC.

The 4 hour Completion Time is reasonable to properly reduce the LEAKAGE increase or verify the source before the reactor must be shut down without unduly jeopardizing plant safety.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B is not met or if pressure boundary LEAKAGE exists, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable,

(continued)

BASES

APPLICABILITY (continued)

below this pressure, the OPERABILITY requirements for the Emergency Core Cooling systems (ECCS) (LCO 3.5.1, "ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODE 3 below the cut-in permissive pressure and in MODE 5 are discussed in LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

ACTIONS

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

<u>A.1</u>

With one of the two RHR shutdown cooling subsystems inoperable, except as permitted by LCO Note 2, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function D

(continued)

BASES

ACTIONS

A.1 (continued)

and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Condensate/Feed and Main Steam Systems, the Reactor Water Cleanup System in the decay heat removal mode (by itself or using feed and bleed in combination with the Control Rod Drive System or Condensate/Feed System), and a combination of an ECCS pump and a safety/relief valve.

A.2 and A.3

With both RHR shutdown cooling subsystems inoperable, an alternate method of reactor coolant circulation must be placed into service. This alternate method may be satisfied by placing a recirculation pump in operation. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the importance of the coolant circulation function. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by one of the required RHR shutdown cooling subsystems), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

(continued)

⟨CTS⟩

ACTIONS

	CONDITION	REQUIRED ACTION	COMPLETION TIME	
⟨3.6.H Act 3⟩	B. (continued)	B.2 Verify source of unidentified LEAKAGE increase is not ~~service sensitive type 304 or type 316 austenitic stainless steel~~ intergranular stress corrosion cracking susceptible material.	4 hours	3
⟨3.6.H Act 1⟩ ⟨3.6.H Act 2⟩ ⟨3.6.H Act 3.b⟩	C. Required Action and associated Completion Time of Condition A or B not met. OR Pressure boundary LEAKAGE exists.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours	

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY	
⟨4.6.H⟩	SR 3.4.4.1 Verify RCS unidentified and total LEAKAGE and unidentified LEAKAGE increase are within limits.	~~8~~ 12 hours	4

L ⟨CTS⟩

[1]

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.~~8~~ 7 Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown

⟨3.6.0⟩ LCO 3.4.~~8~~ 7 Two RHR shutdown cooling subsystems shall be OPERABLE~~, and, with no recirculation pump in operation, at least one RHR shutdown cooling subsystem shall be in operation~~. [2]

TSTF-153 Changes not Shown

-----NOTE~~S~~-----

~~1. Both RHR shutdown cooling subsystems and recirculation pumps may be removed from operation for up to 2 hours per 8 hour period.~~ [2]

⟨DOC L.1⟩ ~~2.~~ One RHR shutdown cooling subsystem may be inoperable for up to 2 hours for the performance of Surveillances.

⟨Appl 3.6.0⟩ APPLICABILITY: MODE 3, with reactor steam dome pressure ~~<~~ less than ~~[~~the RHR cut ~~in~~ permissive pressure~~]~~. [3] D

ACTIONS

⟨3.6.0 footnote a⟩ -----NOTES-----

1. LCO 3.0.4 is not applicable.

⟨DOC A.4⟩ 2. Separate Condition entry is allowed for each RHR shutdown cooling subsystem.

CONDITION	REQUIRED ACTION	COMPLETION TIME
⟨3.6.0 Act 1⟩ A. One or two RHR shutdown cooling subsystems inoperable.	A.1 Initiate action to restore RHR shutdown cooling subsystem(s) to OPERABLE status. AND	Immediately
		(continued)

Flow from a jet pump may be used to simulate the flow in the other jet pump with the same riser. This allowance may be used for two jet pumps except that the two jet pumps may not be both of the calibrated jet pumps in the same recirculation loop. This allowance is necessary since one jet pump flow indication instrument line in Unit 1 has failed. An analysis has been performed which demonstrated the acceptability of this method (Refs. 4 and 5). 1

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued) 5

flow ~~and loop flow~~ versus pump speed relationship must be verified.

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow ~~(or jet pump diffuser to lower plenum differential pressure)~~ pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. ~~This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.~~ 5 6

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow ~~and differential pressure~~ patterns are established by plotting historical data as discussed in Reference 2. 5

The 24 hour Frequency has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop OPERABILITY verification.

This SR is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

7 Note 2 allows this SR not to be performed ~~when~~ until 24 hours after THERMAL POWER exceeds ~~is <~~ 25% ~~of~~ RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data. 7

The 24 hours is an acceptable time to establish conditions appropriate to perform this SR. 3

(continued)

BASES (continued)

REFERENCES

1. uFSAR, Section ~~6.3~~.
2. GE Service Information Letter No. 330, including Supplement 1, "Jet Pump Beam Cracks," June 9, 19~~9~~80.
3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.
4. EAS 07-0289, Revision 1, "SAFETY EVALUATION TO JUSTIFY OPERATION WITH LOSS OF JET PUMP FLOW INDICATION FOR QUAD CITIES 1 AND 2," March 1989.
5. NRC SER supporting Quad Cities 1 and 2 Amendments 124 and 121, respectively, May 23, 1990.

All changes are [1] unless otherwise indicated

Safety and Relief Valves

Each unit is designed with nine safety valves, One of which also functions in the relief mode. This valve is a dual function Target Rock safety/relief valve (S/RV). [2]

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety/Relief Valves (S/RVs)

and

BASES

BACKGROUND

safety valves

safety valves and S/RV

The ASME Boiler and Pressure Vessel Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of S/RVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

safety valves

[2] Insert BKGD-1

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The S/RVs ~~can~~ actuate ~~by either of two modes: the safety mode or the relief mode.~~ In the safety mode (or spring mode of operation), ~~the spring loaded pilot valve opens when steam pressure at the valve inlet overcomes the spring force holding the pilot valve closed. Opening the pilot valve allows a pressure differential to develop across the main valve piston and opens the main valve.~~ This satisfies the Code requirement. [2] In this mode, Insert BKGD-2

The ~~Each~~ relief valves and S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. All other safety valves discharge directly to the drywell.

Insert BKGD-3

[2] Two of the five relief valves

relief

~~The S/RVs that provide the relief mode~~ are the ~~low~~-low set ~~(LLS)~~ valves and ~~the~~ Automatic Depressurization System (ADS) valves. The ~~LLS~~ requirements are specified in LCO 3.6.1.6, "~~Low-Low Set (LLS)~~ Valves," and the ADS requirements are specified in LCO 3.5.1, "ECCS—Operating." [2] [2] all of the relief valves, including the S/RV are

Low Set Relief — [2] — low set relief

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs), followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 1). For the purpose of the analyses, ~~[11] S/RVs~~ nine safety valves (including the S/RV) [3] are assumed to operate in the safety mode. The analysis results demonstrate that the design ~~S/RV~~ safety valve capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design

[2] The relief valves are not credited to function during this event.

(continued)

BASES

s are 2

APPLICABILITY (continued)

In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit ~~is~~ unlikely to be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S/RV function ~~is~~ not needed during these conditions.

and MCPR 2

s 1 are

safety and relief 1

ACTIONS

A.1

relief 1 relief valve (or S/RV)

With the ~~safety~~ function of one ~~[or two]~~ ~~[required]~~ S/RV ~~[s]~~ inoperable, the remaining OPERABLE S/RVs are capable of providing the necessary ~~overpressure~~ protection. ~~Because of additional design margin, the ASME Code limits for the RCPB can also be satisfied with two S/RVs inoperable.~~ However, the overall reliability of the pressure relief system is reduced because additional failures in the remaining OPERABLE S/RVs could result in failure to adequately relieve pressure during a limiting event. For this reason, continued operation is permitted for a limited time only.

relief valves 1

3

The 14 day Completion Time to restore the inoperable required S/RVs to OPERABLE status is based on the relief capability of the remaining S/RVs, the low probability of an event requiring S/RV actuation, and a reasonable time to complete the Required Action.

relief valve 1

relief valves 1

B.1 and B.2

safety valves

With less than the minimum number of required S/RVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the ~~safety~~ function of the inoperable ~~required S/RVs~~ cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1, or if the safety function of ~~[three]~~ or more ~~[required]~~ S/RVs is inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

1 relief valves

relief 1

one 3

safety valves 1

(continued)

the relief function of two or more relief valves are inoperable, or if 1

BASES (continued)

ACTIONS

A.1

With RCS unidentified or total LEAKAGE greater than the limits, actions must be taken to reduce the leak. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours is allowed to reduce the LEAKAGE rates before the reactor must be shut down. If an unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE; however, the total LEAKAGE limit would remain unchanged.

B.1 and B.2

24 — 3

An unidentified LEAKAGE increase of > 2 gpm within a 4 hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated. Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be determined not to be the source of the LEAKAGE increase within the required Completion Time. For an unidentified LEAKAGE increase greater than required limits, an alternative to reducing LEAKAGE increase to within limits (i.e., reducing the LEAKAGE rate such that the current rate is less than the "2 gpm increase in the previous [4] hours" limit; either by isolating the source or other possible methods) is to ~~evaluate service sensitive type 304 and type 316 austenitic stainless steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids and determine it is not the source of the increased LEAKAGE. This type piping is very susceptible to IGSCC.~~

2 — 24

verify the source of the unidentified leakage increase is not material

3

The 4 hour Completion Time is reasonable to properly reduce the LEAKAGE increase or verify the source before the reactor must be shut down without unduly jeopardizing plant safety.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B is not met or if pressure boundary LEAKAGE exists, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable,

(continued)

BASES

BACKGROUND (continued)

~~If the sump fills to the high level setpoint before the timer ends, an alarm sounds in the control room, indicating a LEAKAGE rate into the sump in excess of a preset limit.~~ 2

Insert BCKGD 1

2

Insert BCKGD 2

a flow input to a

A flow ~~indicator~~ monitor in the discharge line of the drywell floor drain sump pumps provides flow ~~indication~~ integrator in the control room. The pumps can also be started from the control room.

The primary containment ~~air~~ atmospheric particulate monitoring systems continuously monitor the primary containment atmosphere for airborne particulate ~~and gaseous~~ radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. The primary containment atmosphere particulate ~~and gaseous radioactivity~~ monitoring systems ~~are~~ not capable of quantifying LEAKAGE rates, ~~but are sensitive enough to indicate increased LEAKAGE rates of 1 gpm within 1 hour. Larger changes in LEAKAGE rates are detected in proportionally shorter times (Ref. 3).~~ 2

satisfies the Regulatory Guide 1.45 (Ref. 2) recommended sensitivity of 1.0 E-9 μCi/cc radioactivity for airborne particulates.

5 15

~~[Condensate from four of the six primary containment coolers is routed to the primary containment floor drain sump and is monitored by a flow transmitter that provides indication and alarms in the control room. This primary containment air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS unidentified LEAKAGE.]~~ 3

APPLICABLE SAFETY ANALYSES

2

The drywell floor drain sump monitoring system

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the LEAKAGE emitted from a single crack in the RCPB (Refs. 4 and 5). ~~Each of the leakage detection systems inside the drywell~~ is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits~~, and providing appropriate alarm of excess LEAKAGE in the control room~~.

2

, provided by the primary containment atmospheric particulate monitoring system,

A control room alarm allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 6). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

(continued)

The primary containment atmospheric particulate monitoring system provides indication of changes in leakage rates. 2

APPLICABILITY (continued)

the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

2

The requirements for decay heat removal in MODE 3 below the cut in permissive pressure and in MODE 5 are discussed in LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

6 7

ACTIONS

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

2 B

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, except as permitted by LCO Note 2, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour

5 D

(continued)

ACTIONS

A.1 (continued)

Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the ~~Spent Fuel Pool Cooling System and~~ the Reactor Water Cleanup System.

3 Condensate/Feed and Main Steam Systems,

in the decay heat removal mode (by itself or using feed and bleed in combination with Control Rod Drive System or Condensate/Feed System), and a combination of an ECCS pump and a safety/relief valve.

1

A.2 ~~B.1~~ and A.3 ~~B.2~~ 1

With both RHR shutdown cooling subsystem inoperable

~~With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as permitted by LCO Note 1, and until RHR or recirculation pump operation is re-established,~~ an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the importance of the coolant circulation function ~~and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.~~ Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

D 1

This alternate method may be satisfied by placing a recirculation pump in operation.

1

During the period when the reactor coolant is being circulated by an alternate method (other than by one of the ~~the~~ required RHR shutdown cooling subsystems ~~System or recirculation pump~~), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

1

Insert ACTIONS

1

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.10.2 9

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS pressure and temperature must be verified within the appropriate limits before withdrawing control rods that will make the reactor critical.

Performing the Surveillance within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal.

1
TSTF-353 changes not adopted

SR 3.4.10.3 and SR 3.4.10.4 9 9 1

Differential temperatures within the applicable ~~PTLR~~ limits ensure that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits ensures that the assumptions of the analysis for the startup of an idle recirculation loop (Ref. 8) are satisfied. 2

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the idle pump start.

5
An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.9.3 is to compare the temperatures on the bottom head drain line and the saturation temperature corresponding to reactor steam dome pressure.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.10.4 is to compare the temperatures of the operating recirculation loop and the idle loop. 1 9

1 9
SR 3.4.10.3 ~~has~~ and SR 3.4.9.4 have been modified by a Note that requires the Surveillance to be performed only in MODES 1, 2, 3, and 4 ~~with reactor steam dome pressure ≥ 25 psig.~~ In MODE 5, the overall stress on limiting components is lower. Therefore, ΔT limits are not required. 5

The Note also states the SRs are only required to be met during a recirculation pump startup, since this is when the stresses occur. 5

SR 3.4.10.5, SR 3.4.10.6, and SR 3.4.10.7 9 1

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify, for each required ECCS injection/spray subsystem, the: a. Suppression pool water level is $\geq$ 8.5 ft; or b. -----------------NOTE---------------- Only one required ECCS injection/spray subsystem may take credit for this option during OPDRVs. ------------------------------------- Contaminated condensate storage tank(s) water volume is $\geq$ 140,000 available gallons.	12 hours
SR 3.5.2.2	Verify, for each required ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	31 days
SR 3.5.2.3	-------------------NOTE------------------ One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable. --- Verify each required ECCS injection/spray subsystem manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days

(continued)

BASES

LCO (continued)

the limits specified in Reference 10 could be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by Reference 10.

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut-in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes: a) when the system is being realigned to or from the RHR shutdown cooling mode and; b) when the system is in the RHR shutdown cooling mode, whether or not the RHR pump is operating. 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.

D

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 $\leq$ 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.1

If any one LPCI pump is inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE pumps provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE LPCI subsystems, concurrent with a LOCA, may result in the LPCI subsystems not being able to perform their intended safety function. The 30 day Completion Time is based on a reliability study cited in Reference 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 allowable repair times (i.e., Completion Times).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the HPCI System, this SR also includes the steam flow path for the turbine and the flow controller position.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve position would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

In MODE 3 with reactor steam dome pressure less than the actual RHR cut-in permissive pressure, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, this SR is modified by a Note that allows LPCI subsystems to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes: a) when the system is being realigned to or from the RHR shutdown cooling mode and; b) when the system is in the RHR shutdown cooling mode, whether or not the RHR pump is operating. At the low pressures and decay heat loads associated with operation in MODE 3 with reactor steam dome pressure less than the RHR cut-in permissive pressure, a reduced complement of low pressure ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling, when necessary. D

(continued)

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

B 3.5.2 ECCS – Shutdown

BASES

BACKGROUND

A description of the Core Spray (CS) System and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System is provided in the Bases for LCO 3.5.1, "ECCS – Operating."

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated loss of coolant accident (LOCA). The long term cooling analysis following a design basis LOCA (Ref. 1) demonstrates that only one low pressure ECCS injection/spray subsystem is required, post LOCA, to maintain adequate reactor vessel water level in the event of an inadvertent vessel draindown. It is reasonable to assume, based on engineering judgement, that while in MODES 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level. To provide redundancy, a minimum of two low pressure ECCS injection/spray subsystems are required to be OPERABLE in MODES 4 and 5.

The low pressure ECCS subsystems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two low pressure ECCS injection/spray subsystems are required to be OPERABLE. The low pressure ECCS injection/spray subsystems consist of two CS subsystems and two LPCI subsystems. Each CS subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or contaminated condensate storage tank(s) (CCST) to the reactor pressure vessel (RPV). Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or the CCST(s) to the RPV. A single LPCI pump is required per subsystem because of similar injection capacity in relation to a CS subsystem. In addition, In MODES 4 and 5, the RHR System cross-tie valves are not required to be open.

One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal, if capable

(continued)

BASES

LCO (continued

of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes: a) when the system is being realigned to or from the RHR shutdown cooling mode and; b) when the system is in the RHR shutdown cooling mode, whether or not the RHR pump is operating. Because of low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery.

D

APPLICABILITY

OPERABILITY of the low pressure ECCS injection/spray subsystems is required in MODES 4 and 5 to ensure adequate coolant inventory and sufficient heat removal capability for the irradiated fuel in the core in case of an inadvertent draindown of the vessel. Requirements for ECCS OPERABILITY during MODES 1, 2, and 3 are discussed in the Applicability section of the Bases for LCO 3.5.1. ECCS subsystems are not required to be OPERABLE during MODE 5 with the spent fuel storage pool gates removed and the water level maintained at ≥ 23 ft above the RPV flange. This provides sufficient coolant inventory to allow operator action to terminate the inventory loss prior to fuel uncovery in case of an inadvertent draindown.

The Automatic Depressurization System is not required to be OPERABLE during MODES 4 and 5 because the RPV pressure is ≤ 150 psig, and the CS System and the LPCI subsystems can provide core cooling without any depressurization of the primary system.

The High Pressure Coolant Injection System is not required to be OPERABLE during MODES 4 and 5 since the low pressure ECCS injection/spray subsystems can provide sufficient flow to the vessel.

ACTIONS

A.1 and B.1

If any one required low pressure ECCS injection/spray subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status in 4 hours. In this Condition, the remaining OPERABLE subsystem can provide sufficient vessel flooding capability to recover from an inadvertent vessel draindown. However, overall system reliability is

(continued)

BASES

ACTIONS

C.1, C.2, D.1, D.2, and D.3 (continued)

available in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability. The administrative controls may 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 is indicated). OPERABILITY may be verified by an administrative check, or by examining logs or other information, to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

The minimum water level of 8.5 feet above the bottom of the suppression chamber required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the CS System and LPCI subsystem pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, all ECCS injection/spray subsystems are inoperable unless they are aligned to an OPERABLE CCST(s).

When suppression pool level is < 8.5 feet, the CS and LPCI subsystems are considered OPERABLE only if they can take suction from the CCST(s), and the CCST(s) water volume is sufficient to provide the required NPSH and vortex prevention for the CS pump and LPCI pump. Therefore, a verification that either the suppression pool water level is ≥ 8.5 feet or that required low pressure ECCS injection/spray subsystems are aligned to take suction from the CCST(s) and the CCST(s) contain ≥ 140,000 available

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 (continued)

gallons of water, equivalent to 12 ft in both CCSTs when they are crosstied (normal configuration) and 13.5 ft in one CCST when they are not crosstied, ensures that the required low pressure ECCS injection/spray subsystems can supply at least 140,000 gallons of makeup water to the RPV. However, as noted, only one required low pressure ECCS injection/spray subsystem may take credit for the CCST option during OPDRVs. During OPDRVs, the volume in the CCST(s) may not provide adequate makeup if the RPV were completely drained. Therefore, only one low pressure ECCS injection/spray subsystem is allowed to use the CCST(s). This ensures the other required ECCS subsystem has adequate makeup volume.

The 12 hour Frequency of these SRs was developed considering operating experience related to suppression pool water level and CCST water level variations and instrument drift during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool or CCST water level condition.

SR 3.5.2.2, SR 3.5.2.4, and SR 3.5.2.5

The Bases provided for SR 3.5.1.1, SR 3.5.1.5, and SR 3.5.1.8 are applicable to SR 3.5.2.2, SR 3.5.2.4, and SR 3.5.2.5, respectively.

SR 3.5.2.3

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.3 (continued)

involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is appropriate because the valves are operated under procedural control and the probability of their being mispositioned during this time period is low.

In MODES 4 and 5, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, this SR is modified by a Note that allows one LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes: a) when the system is being realigned to or from the RHR shutdown cooling mode and; b) when the system is in the RHR shutdown cooling mode, whether or not the RHR pump is operating. Because of the low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery. This will ensure adequate core cooling if an inadvertent RPV draindown should occur. D

REFERENCES

1. UFSAR, Section 6.3.3.1.2.1.

A.1

ITS 3.5.2

SR 3.5.2.2
SR 3.5.2.3
SR 3.5.2.4
SR 3.5.2.5

LD.1

3.5 - LIMITING CONDITIONS FOR OPERATION

B. Emergency Core Cooling System - Shutdown (low pressure ECCS injection/Spray subsystems)

At least two ~~of the following four~~ subsystems/loops shall be OPERABLE[a]:

LA.1

1. ~~One or both core spray (CS) subsystems with:~~

   a. ~~An OPERABLE flow path capable of taking suction from at least one of the following water sources and transferring the water through the spray sparger to the reactor vessel:~~

      1) ~~From the suppression chamber, or~~

      2) ~~When the suppression chamber water level is less than the limit or is drained, from the condensate storage tank~~ containing at least 140,000 available gallons of water.

SR 3.5.2.1.b

2. ~~One or both low pressure coolant injection (LPCI) subsystem loops with a subsystem loop comprised of:~~

   a. ~~At least one OPERABLE LPCI pump, and~~

   b. ~~An OPERABLE flow path capable of taking suction from at least one of the following water sources and transferring the water to the reactor vessel:~~

      1) ~~From the suppression chamber, or~~

LA.1

4.5 - SURVEILLANCE REQUIREMENTS

B. Emergency Core Cooling System - Shutdown

The required ECCS shall be demonstrated OPERABLE per Surveillance Requirement 4.5.A, except:

A.2

1. ~~The LPCI subsystems cross-tie valves may be closed.~~

LA.1

SR 3.5.2.4 2. Each LPCI pump develops the required flow when tested pursuant to Specification 4.0.E.

M.1

add proposed flow rate and head conditions for one pump

D

SR 3.5.2.3 Note

a One LPCI subsystem may be aligned for decay heat removal and considered OPERABLE for the ECCS function, if it can be manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable.

LA.2

Page 1 of 4

A.1

ITS 3.5.2

LA.1

SR 3.5.2.1.b

2) ~~When the suppression chamber water level is less than the limit or is drained, from the condensate storage tank~~ containing at least 140,000 available gallons of water.

D

APPLICABILITY:

OPERATIONAL MODE(s) 4 and 5[b].

ACTION:

ACTION A

1. With one of the above required subsystems/loops inoperable, restore at least two subsystems/loops to OPERABLE status within 4 hours or

ACTION B

suspend all operations with a potential for draining the reactor vessel.

ACTION C

2. With both of the above required subsystems/loops inoperable, suspend ~~CORE ALTERATION(s) and~~ all operations with a potential for draining the reactor vessel. Restore at least one subsystem/loop to OPERABLE status within 4 hours or establish

ACTION D

SECONDARY CONTAINMENT INTEGRITY within the next 8 hours.

L.1

A.3

A.4

A.5

Applicability b The ECCS is not required to be OPERABLE ~~provided that the reactor vessel head is removed, the cavity is flooded,~~ the spent fuel pool gates are removed, and water level is maintained within the limits of Specification 3.10.G and 3.10.H.

3.5 - LIMITING CONDITIONS FOR OPERATION

C. Suppression Chamber

A.6 moved to ITS 3.6.2.2

The suppression chamber shall be OPERABLE:

1. In OPERATIONAL MODE(s) 1, 2, and 3 with a contained water volume equivalent to a water level of ≥ 14' 1" above the bottom of the suppression chamber.

SR 3.5.2.1
SR 3.5.2.2.a

LA.1

2. In OPERATIONAL MODE(s) 4 and 5[a] with a contained volume equivalent to a water level of ≥8.5' above the bottom of the suppression chamber, except that the suppression chamber level may be less than the limit provided that:

L.2

a. ~~No operations are performed that have a potential for draining the reactor vessel,~~

L.3

b. ~~The reactor mode switch is locked in the Shutdown or Refuel position,~~

SR 3.5.2.1.b

c. The condensate storage tank contains ≥ 140,000 available gallons of water, and

add proposed SR 3.5.2.1.b Note

LCO 3.5.2

d. The ECCS systems are OPERABLE per Specification 3.5.B.

4.5 - SURVEILLANCE REQUIREMENTS

C. Suppression Chamber

The suppression chamber shall be determined OPERABLE by verifying:

1. For OPERATIONAL MODE(s) 1, 2 and 3, at least once per 24 hours, the water level to be ≥ 14' 1".

2. For OPERATIONAL MODE(s) 4 or 5[a], at least once per 12 hours:

L.4

SR 3.5.2.1.a a. The water level to be ≥8.5', or

SR 3.5.2.1.b b. Verify the alternate conditions of Specification 3.5.C.2, or the conditions of footnote (a), to be satisfied.

A.7

D

APPLICABILITY:

OPERATIONAL MODE(s) 1, 2, 3, 4 and 5[a].

A.6 moved to ITS 3.6.2.2

A.5

Applicability

a The suppression chamber is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded or being flooded from the suppression pool, the spent fuel pool gates are removed when the cavity is flooded and the water level is maintained within the limits of Specification 3.10.G and 3.10.H.

M.2

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd) specifies that no operations are performed that have a potential for draining the reactor vessel (revised as discussed in Discussion of Change L.2), the reactor mode switch is locked in the shutdown or Refuel position (deleted as discussed in Discussion of Change L.3), the condensate storage tank contains a specified volume of water (the 12 hour Frequency will be retained as indicated in proposed SR 3.5.2.1.b), and the ECCS are OPERABLE per Specification 3.5.B.

In the ITS, the requirements of 3/4.5.C and 3/4.5.B are incorporated in one Specification (ITS 3.5.2) and only the normal Surveillance Frequencies are proposed. This change is based on the fact that it is overly conservative to assume that systems or components are inoperable when a surveillance has not been performed. The opposite is in fact the case, the vast majority of surveillances demonstrate that systems or components in fact are operable. Therefore, even with low suppression pool level, the normal frequencies (e.g., LPCI testing in accordance with the Inservice Testing Frequency) are considered sufficient to ensure the OPERABILITY of the systems and that the parameters are within limits.

RELOCATED SPECIFICATIONS

None

All Changes are $\boxed{2}$ unless otherwise indicated

⟨CTS⟩

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

3.5.1 ECCS—Operating

⟨3.5.A⟩ LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of ~~[seven]~~ four $\boxed{1}$ ~~safety/~~ relief valves shall be OPERABLE. $\boxed{D}$

⟨Appl 3.5.A⟩ 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. $\boxed{1}$

Insert ACTIONS A, B, C and D

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~A. One low pressure ECCS injection/spray subsystem inoperable.~~	~~A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.~~	~~7 days~~
⟨3.5.A Act 1.a⟩ ⟨3.5.A Act 2.a⟩ ⟨3.5.A Act 2.b⟩ 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
⟨3.5.A Act 3⟩ F. HPCI System inoperable.	F.1 Verify by administrative means RCIC System is OPERABLE. AND F.2 Restore HPCI System to OPERABLE status.	~~1 hour~~ Immediately $\boxed{11}$ 14 days

(continued)

<CTS>

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

3.5.2 ECCS—Shutdown

<3.5.B>
<3.5.C.2.d>

LCO 3.5.2 Two low pressure ECCS injection/spray subsystems shall be OPERABLE.

<Appl. 3.5.B>
<Appl 3.5.C>

APPLICABILITY: MODE 4,
MODE 5, except with the spent fuel storage pool gates removed and water level ≥ [23 ft] over the top of the reactor pressure vessel flange. [1]

ACTIONS

	CONDITION	REQUIRED ACTION	COMPLETION TIME
<3.5.B Act 1>	A. One required ECCS injection/spray subsystem inoperable.	A.1 Restore required ECCS injection/spray subsystem to OPERABLE status.	4 hours
3.5.B Act 1	B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action to suspend operations with a potential for draining the reactor vessel (OPDRVs).	Immediately
3.5.B Act 2 3.5.C Act 2	C. Two required ECCS injection/spray subsystems inoperable.	C.1 Initiate action to suspend OPDRVs. AND C.2 Restore one required ECCS injection/spray subsystem to OPERABLE status. [4]	Immediately 4 hours

(continued)

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE		FREQUENCY
<4.5.C.2> <3.5.C.2> <3.5.C.2.c> <3.5.B.1.a.2> <3.5.B.2.b.2>	SR 3.5.2.~~2~~ 2 1	Verify, for each required ~~core spray (CS)~~ ECCS injection/spray subsystem, the: 2 a. Suppression pool water level is ≥ ~~[12 ft 2 inches]~~ 8.5 ft 1; or b. ----------NOTE---------- Only one required ~~CS~~ ECCS injection/spray subsystem may take credit for this option during OPDRVs. ------------------------------ Contaminated 3 Condensate storage tank(s) water ~~level~~ volume is ≥ ~~[12 ft]~~ 140,000 available gallons. 1	12 hours
<4.5.B>	SR 3.5.2.~~3~~ 2 2	Verify, for each required ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	31 days
<4.5.B>	SR 3.5.2.~~4~~ 2 3	----------NOTE---------- One LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned and not otherwise inoperable. ------------------------------ Verify each required ECCS injection/spray subsystem manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days

D

(continued)

All changes are [1] unless otherwise indicated

BASES

BACKGROUND (continued)

selected each subsystem

corresponding recirculation loop, begins. The water then enters the reactor through the jet pumps. Full flow test lines are provided for the four LPCI pumps to route water from the suppression pool, to allow testing of the LPCI pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "RHR Suppression Pool Cooling."

and to

The HPCI System (Ref. 3) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping for the system is provided from the CST and the suppression pool. Pump suction for HPCI is normally aligned to the CST source to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, or if the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCI System. The steam supply to the HPCI turbine is piped from a main steam line upstream of the associated inboard main steam isolation valve.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (~~162 psid to 1135 psid, vessel to pump suction~~). Upon receipt of an initiation signal, the HPCI turbine stop valve and turbine control valve open simultaneously and the turbine accelerates to a specified speed. As the HPCI flow increases, the turbine governor valve is automatically adjusted to maintain design flow. Exhaust steam from the HPCI turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the HPCI System during normal operation without injecting water into the RPV.

150 psig to 1120 psig

steam supply

control

C

C

or remain open

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valves in these lines automatically open to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, all ECCS pump discharge lines are filled with water. The LPCI and CS System discharge lines are kept full of water using a "keep fill" system (jockey pump system). The HPCI System is normally aligned to the

(continued)

All changes are 1 unless otherwise indicated

BASES

APPLICABLE SAFETY ANALYSES (continued)

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference ~~0~~ 8. ~~For a large discharge pipe break LOCA, failure of the LPCI valve on the unbroken recirculation loop~~ For GE fuel, the recirculation suction line break with 125 VDC battery failure is considered the most ~~severe failure~~. For a small break LOCA, HPCI failure is the most severe failure. ~~One ADS valve failure is analyzed as a limiting single failure for events requiring ADS operation.~~ Insert ASA-1 Insert ASA-2 The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of ~~the NRC Policy Statement~~ 10 CFR 50.36(c)(2)(ii).

LCO

Each ECCS injection/spray subsystem and ~~seven~~ four ADS valves are required to be OPERABLE. The S/RV can not be used to satisfy the ADS requirement. The ECCS injection/spray subsystems are defined as the two CS subsystems, the two LPCI subsystems, and one HPCI System. The low pressure ECCS injection/spray subsystems are defined as the two CS subsystems and the two LPCI subsystems.

With less than the required number of ECCS subsystems OPERABLE, the potential exists that during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in Reference 10 could be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by Reference 10.

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. 3 INSERT LCO 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. D

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

(continued)

1 INSERT ASA-1

limiting break/failure combination. In addition, to the 125 VDC battery failure, HPCI was assumed to fail to be consistent with generic analyses performed for the BWR 3/4 design generic analysis. For Siemens fuel, the recirculation suction line break with a failure of the entire LPCI System is considered the most limiting break/failure combination.

1 INSERT ASA-2

In the analysis of events requiring ADS operation, it is assumed that only three of the five ADS valves operate. Therefore, four ADS valves are required to be OPERABLE to meet single failure criteria.

3 INSERT LCO

Alignment and operation for decay heat removal includes: a) when the system is being realigned to or from the RHR shutdown cooling mode and; b) when the system is in the RHR shutdown cooling mode, whether or not the RHR pump is operating. D

3 INSERT SR 3.5.1.2A

In MODE 3 with reactor steam dome pressure less than the actual RHR cut-in permissive pressure, the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore,

3 INSERT SR 3.5.1.2B

Alignment and operation for decay heat removal includes: a) when the system is being realigned to or from the RHR shutdown cooling mode and; b) when the system is in the RHR shutdown cooling mode, whether or not the RHR pump is operating. At the low pressures and decay heat loads associated with operation in MODE 3 with reactor steam dome pressure less than the RHR cut-in permissive pressure, a reduced complement of low pressure ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling, when necessary. D

BASES

4 — 4

SURVEILLANCE REQUIREMENTS

4

SR 3.5.1.~~6~~ (continued)

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

~~startup prior to reaching > 25% RTP is an exception to the normal Inservice Testing Program generic valve cycling Frequency of 92 days, but is considered acceptable due to the demonstrated reliability of these valves.~~ If ~~the~~ any recirculation pump discharge valve is inoperable and in the open position, ~~the associated~~ both LPCI subsystem must be declared inoperable.

1 — 5 — 1 — 1

4 — SR 3.5.1.~~7~~ 5, SR 3.5.1.~~8~~ 6, and SR 3.5.1.~~9~~ 7

The performance requirements of the low pressure ECCS pumps are determined through application of the 10 CFR 50, Appendix K criteria (Ref. 8). This periodic Surveillance is performed (in accordance with the ASME Code, Section XI, requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The low pressure ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of Reference 10. The pump flow rates are verified against a test line pressure or system head equivalent to the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during a LOCA. These values ~~may be~~ have been established ~~during preoperational testing~~ analytically.

4 — 1

The flow tests for the HPCI System are performed at two different pressure ranges such that system capability to provide rated flow against a system head corresponding to reactor pressure is tested at both the higher and lower operating ranges of the system. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Reactor steam pressure must be ≥ ~~[~~920~~]~~ psig to perform SR 3.5.1.~~8~~ 6 and ≥ ~~[~~150~~]~~ psig to perform SR 3.5.1.~~9~~ 7. Adequate steam flow is represented by ~~[at least 1.25~~ turbine bypass valves open, or total steam flow ≥ 10^6 lb/hr~~]~~. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these tests. Reactor startup is allowed prior to performing the low pressure Surveillance test because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance test is short. The reactor pressure is allowed to be increased to normal

3 — 3

Insert SR 3.5.1.6

3 — 6 — 2 — 6 — 4 — 7 — 3

(continued)

All changes are 1 unless otherwise noted

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

B 3.5.2 ECCS—Shutdown

BASES

BACKGROUND

A description of the Core Spray (CS) System and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System is provided in the Bases for LCO 3.5.1, "ECCS—Operating."

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated loss of coolant accident (LOCA). The long term cooling analysis following a design basis LOCA (Ref. 1) demonstrates that only one low pressure ECCS injection/spray subsystem is required, post LOCA, to maintain adequate reactor vessel water level in the event of an inadvertent vessel draindown. It is reasonable to assume, based on engineering judgement, that while in MODES 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level. To provide redundancy, a minimum of two low pressure ECCS injection/spray subsystems are required to be OPERABLE in MODES 4 and 5.

The low pressure ECCS subsystems satisfy Criterion 3 of ~~the NRC Policy Statement~~ 10 CFR 50.36(c)(2)(ii).

LCO

Two low pressure ECCS injection/spray subsystems are required to be OPERABLE. The low pressure ECCS injection/spray subsystems consist of two CS subsystems and two LPCI subsystems. Each CS subsystem consists of one motor driven pump, piping, and valves to transfer water from the contaminated suppression pool or condensate storage tank(s) (CST) to the reactor pressure vessel (RPV). Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or the CCST(s) to the RPV. ~~Only~~ ~~a~~ single LPCI pump is required per subsystem because of ~~the larger~~ similar injection capacity in relation to a CS subsystem. In addition, in MODES 4 and 5, the RHR System cross-tie valves ~~is~~ are not required to be ~~closed~~ open. C D D

(continued)

2

INSERT LCO

Alignment and operation for decay heat removal includes: a) when the system is being realigned to or from the RHR shutdown cooling mode and; b) when the system is in the RHR shutdown cooling mode, whether or not the RHR pump is operating.

D

All changes are [1] unless otherwise indicated

BASES

ACTIONS

C.1, C.2, D.1, D.2, and D.3 (continued)

necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

move to previous page

The 4 hour Completion Time to restore at least one low pressure ECCS injection/spray subsystem to OPERABLE status ensures that prompt action will be taken to provide the required cooling capacity or to initiate actions to place the plant in a condition that minimizes any potential fission product release to the environment. [2]

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 ~~and SR 3.5.2.2~~ [3]

8.5 ft [4] above the bottom of the suppression chamber

The minimum water level of ~~[12 ft 2 inches]~~ required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the CS System and LPCI subsystem pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, all ~~ECCS injection/spray subsystems~~ required low pressure ECCS injection/spray subsystems are inoperable unless they are aligned to an OPERABLE CST.

required low pressure injection/spray subsystems

When suppression pool level is < ~~[12 ft 2 inches]~~ 8.5 ft [4], the ~~CS System is~~ required low pressure ECCS injection/spray subsystems are and LPCI subsystems are considered OPERABLE only if ~~it~~ they can take suction from ~~the~~ CST(s) and the CST(s) water ~~level~~ volume is sufficient to provide the required NPSH for the CS pump and LPCI pump or vortex prevention. Therefore, a verification that either the suppression pool water level is ≥ ~~[12 ft 2 inches]~~ 8.5 ft [4] or that ~~CS is~~ C aligned to take suction from ~~the~~ CST(s) and the CST(s) contain(s) ≥ ~~[150,000]~~ 140,000 [4] gallons of water, available equivalent to ~~12 ft~~, ensures that the ~~CS System~~ can supply at least ~~[50,000]~~ 140,000 [4] gallons of makeup water to the RPV. ~~The CS suction is uncovered at the [100,000] gallon level.~~ However, as noted, only one required ~~CS~~ subsystem may take credit for the CST option during OPDRVs. During OPDRVs, the volume in the CST may not provide adequate makeup if the RPV were completely drained. Therefore, only one ~~CS~~ low pressure ECCS injection/spray subsystem is allowed to use the CST. This ensures the other required ECCS subsystem has adequate makeup volume. D

12 ft in both CCSTs when they are crosstied (normal configuration) and 13.5 ft in one CCST when they are not crosstied C

(continued)

2 INSERT SR 3.5.2.3

Alignment and operation for decay heat removal includes: a) when the system is being realigned to or from the RHR shutdown cooling mode and: b) when the system is in the RHR shutdown cooling mode, whether or not the RHR pump is operating. Because of the low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery. D

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1.1	Perform required visual examinations and leakage rate testing except for primary containment air lock testing, in accordance with the Primary Containment Leakage Rate Testing Program.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.1.2	Verify drywell-to-suppression chamber bypass leakage is $\leq$ 2% of the acceptable $A/\sqrt{k}$ design value of 0.18 ft^2 at an initial differential pressure of $\geq$ 1.0 psid.	24 months AND ------NOTE----- Only required after two consecutive tests fail and continues until two consecutive tests pass --------------- 12 months

D

C

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.4.1	Verify each RHR suppression pool spray subsystem manual and power operated valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	31 days
SR 3.6.2.4.2	Verify each suppression pool spray nozzle is unobstructed.	10 years

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 secondary containment vacuum is $\geq$ 0.10 inch of vacuum water gauge.	24 hours
SR 3.6.4.1.2	Verify one secondary containment access door in each access opening is closed.	31 days
SR 3.6.4.1.3	Verify the secondary containment can be maintained $\geq$ 0.25 inch of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate $\leq$ 4000 cfm.	24 months on a STAGGERED TEST BASIS for each SGT subsystem
SR 3.6.4.1.4	Verify all secondary containment equipment hatches are closed and sealed.	24 months

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. Failure to meet air lock leakage limit (SR 3.6.1.2.1) or main steam isolation valve leakage limit (SR 3.6.1.3.10) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program.

As left leakage prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test is required to be $< 0.6\ L_a$ for combined Type B and C leakage, and $\leq 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.1.2

Maintaining the pressure suppression function of the primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the downcomers into the suppression pool. This SR measures drywell-to-suppression chamber differential pressure during a 15 minute period to ensure that the leakage paths that would bypass the suppression pool are within allowable limits.

Satisfactory performance of this SR can be achieved by establishing a known differential pressure ($\geq$ 1.0 psid) between the drywell and the suppression chamber and verifying that the measured bypass leakage is $\leq$ 2% of the acceptable $A/\sqrt{k}$ design value of 0.18 ft^2. The leakage test is performed every 24 months. The 24 month Frequency was developed considering it is prudent that this Surveillance be performed during a unit outage and also in view of the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.2 (continued)

fact that component failures that might have affected this test are identified by other primary containment SRs. Two consecutive test failures, however, would indicate unexpected primary containment degradation, in this event, the Note indicates, increasing the Frequency to once every 12 months is required until the situation is remedied as evidenced by passing two consecutive tests.

REFERENCES

1. UFSAR, Section 6.2.1.
2. UFSAR, Section 15.6.5.
3. 10 CFR 50, Appendix J, Option B.

BASES

BACKGROUND (continued)

maximum negative containment (drywell and suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary containment spray flow rate and temperature and the assumed initial conditions of the primary containment atmosphere. Low spray temperatures and atmospheric conditions that yield the minimum amount of contained noncondensible gases are assumed for conservatism.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving the reactor building-to-suppression chamber vacuum breakers are presented in Reference 1 as part of the accident response of the containment systems. Internal (suppression-chamber-to-drywell) and external (reactor building-to-suppression chamber) vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls, which form part of the primary containment boundary.

The safety analyses assume the external vacuum breakers to be closed initially, with the mechanical vacuum breakers counter balanced to open at 0.5 psid and to be fully open in one second. The air operated butterfly valve vacuum breakers are assumed to open concurrent with the mechanical vacuum breakers and be full open in one second (Ref. 2). D Since only one of the two parallel 20 inch vacuum breaker lines is required to protect the suppression chamber from excessive negative differential pressure, the single active failure criterion is satisfied. Design Basis Accident (DBA) analyses assume the vacuum breakers to be closed initially and that at least one vacuum breaker in each line remains closed and leak tight with positive primary containment pressure.

Four cases were considered in the safety analyses to determine the adequacy of the external vacuum breakers:

a. A small steam line break loss of coolant accident followed by actuation of one drywell and suppression pool spray loop; C

b. An intermediate steam line break loss of coolant accident followed by actuation of one drywell and suppression pool spray loop;

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1 (continued)

Two Notes are added to this SR. The first Note allows reactor-to-suppression chamber vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers. The second Note is included to clarify that vacuum breakers open due to an actual differential pressure are not considered as failing this SR.

SR 3.6.1.7.2

Each vacuum breaker must be cycled to ensure that it opens properly to perform its design function and returns to its fully closed position. This ensures that the safety analysis assumptions are valid. The 92 day Frequency of this SR was developed based upon Inservice Testing Program requirements to perform valve testing at least once every 92 days.

SR 3.6.1.7.3

Demonstration of vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of $\leq$ 0.5 psid is valid. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. For this plant, the 24 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

REFERENCES

1. UFSAR, Sections 6.2.1.3.3 and 6.3.3.2.9.
2. UFSAR, Section 6.2.1.2.4.1.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1 (continued)

accident analysis. This is acceptable since the RHR suppression pool spray mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

SR 3.6.2.4.2

This Surveillance is performed every 10 years to verify that the spray nozzles are not obstructed and that spray flow will be provided when required. The 10 year Frequency is adequate to detect degradation in performance due to the passive nozzle design and has been shown to be acceptable through operating experience.

REFERENCES

1. UFSAR, Section 6.2.2.2.

ACTIONS

C.1, C.2, and C.3 (continued)

any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations during the applicable MODES and the low probability of a DBA occurring.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.

SR 3.6.4.1.2 and SR 3.6.4.1.4

Verifying that one secondary containment access door in each access opening is closed and each equipment hatch is closed and sealed 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. In this application, the term "sealed" has no connotation of leak tightness. In addition, for equipment hatches that are floor plugs, the "sealed" requirement is effectively met by gravity. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed. An access opening contains one inner and one outer door. In some cases a secondary containment barrier contains multiple inner or multiple outer doors. For these cases, the access opening share the inner door or the outer door, i.e., the access openings have a common inner or outer door. The intent is to not breach

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.2 and SR 3.6.4.1.4 (continued)

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; i.e., all inner doors closed or all outer doors closed. Thus each access opening has one door closed. 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. The 31 day Frequency for SR 3.6.4.1.2 has been shown to be adequate, based on operating experience, and is considered adequate in view of the other indications of door status that are available to the operator. The 24 month Frequency for SR 3.6.4.1.4 is considered adequate in view of the existing administrative controls on equipment hatches.

SR 3.6.4.1.3

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. Each SGT subsystem is designed to maintain the secondary containment at $\geq$ 0.25 inches of vacuum water gauge for 1 hour at a flow rate of $\leq$ 4000 cfm. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.3 verifies that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can be maintained. When the SGT System is operating as designed, the maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. SR 3.6.4.1.3 demonstrates that the pressure in the secondary containment can be maintained $\geq$ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate $\leq$ 4000 cfm. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. The primary purpose of the SR is to ensure secondary containment boundary integrity. The secondary purpose of the SR is to ensure that the SGT subsystem being tested functions as designed. There is a separate LCO with Surveillance Requirements that serves the primary purpose of ensuring OPERABILITY of the SGT System. This SR need not be performed with each SGT subsystem. The SGT subsystem used for this Surveillance is staggered to ensure that in

(continued)

ITS 3.6.1.1

A.1

3.7 - LIMITING CONDITIONS FOR OPERATION

K. Suppression Chamber

The suppression chamber shall be OPERABLE with:

1. The suppression pool water level between 14' 1" and 14' 5",

2. A suppression pool maximum average water temperature of ≤95°F during OPERATIONAL MODE(s) 1 or 2, except that the maximum average temperature may be permitted to increase to:

   a. ≤105°F during testing which adds heat to the suppression pool.

   b. ≤110°F with THERMAL POWER ≤1% of RATED THERMAL POWER.

   c. ≤120°F with the main steam line isolation valves closed following a scram.

SR 3.6.1.1.2 3. A total leakage between the suppression chamber and drywell of less than the equivalent leakage through a 1 inch diameter orifice at a differential pressure of 1.0 psid. A.6

APPLICABILITY:

OPERATIONAL MODE(s) 1, 2 and 3.

ACTION:

1. With the suppression pool water level outside the above limits, restore the water level to within the limits

← add proposed ACTION A L.1

4.7 - SURVEILLANCE REQUIREMENTS

K. Suppression Chamber

The suppression chamber shall be demonstrated OPERABLE:

1. By verifying the suppression pool water level to be within the limits at least once per 24 hours.

2. At least once per 24 hours by verifying the suppression pool average water temperature to be ≤95°F, except:

   a. At least once per 5 minutes during testing which adds heat to the suppression pool, by verifying the suppression pool average water temperature to be ≤105°F.

   b. At least once per hour when suppression pool average water temperature is ≥95°F, by verifying:

      1) Suppression pool average water temperature to be ≤110°F, and

      2) THERMAL POWER to be ≤1% of RATED THERMAL POWER after suppression pool average water temperature has exceeded 95°F for more than 24 hours. D

   c. At least once per 30 minutes with the main steam line isolation valves closed following a scram and suppression pool average water temperature >95°F, by verifying suppression pool average water temperature to be ≤120°F.

see ITS 3.6.2.1 and ITS 3.6.2.2

3.7 - LIMITING CONDITIONS FOR OPERATION

within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. In OPERATIONAL MODE(s) 1 or 2 with the suppression pool average water temperature >95°F, except as permitted above, restore the average temperature to ≤95°F within 24 hours or reduce THERMAL POWER to ≤1% RATED THERMAL POWER within the next 12 hours.

3. With the suppression pool average water temperature >105°F during testing which adds heat to the suppression pool, except as permitted above, stop all testing which adds heat to the suppression pool and restore the average temperature to ≤95°F within 24 hours or reduce THERMAL POWER to ≤1% RATED THERMAL POWER within the next 12 hours.

4. With the suppression pool average water temperature >110°F, immediately place the reactor mode switch in the Shutdown position and operate at least one residual heat removal loop in the suppression pool cooling mode.

5. With the suppression pool average water temperature >120°F, depressurize the reactor pressure vessel to <150 psig (reactor steam dome pressure) within 12 hours.

<see ITS 3.6.2.1 and 3.6.2.2>

4.7 - SURVEILLANCE REQUIREMENTS

~~3. Deleted.~~

~~4. Deleted~~

24 LD.1

5. At least once per 18 months by conducting a drywell to suppression chamber bypass leak test at an initial differential pressure of 1.0 psid and verifying that the measured leakage is within the specified limit. ~~If any drywell to suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission.~~ If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 9 months until two consecutive tests meet the specified limit, at which time the 18 month test schedule may be resumed.

SR 3.6.1.1.2

D

L.2

C

24

12

LD.1

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.2 The requirement in CTS 4.7.K.5 for the NRC to review the test schedule for subsequent tests if any leak rate test result is not within the required limits has been deleted since the NRC has already approved the test schedule. If one test fails, the current Technical Specifications do not require the test frequency to be changed. The test frequency is only required to be changed if two consecutive tests have failed, as stated in CTS 4.7.K.5. Since the test schedule is already covered by the Technical Specifications, which has been approved by the NRC, there is no reason to have a requirement that the NRC review the test schedule (which will not change from the current test schedule) when one test fails. In addition, a historical review has shown this Surveillance has never failed. Therefore, this change is considered to be acceptable.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A new Surveillance Requirement has been added. This Surveillance Requirement (SR 3.6.2.4.2) verifies each suppression pool spray nozzle is unobstructed every 10 years. This SR is required to ensure that when a suppression pool spray subsystem is required per its design function that it will perform as designed. This SR is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details in the CTS 3.7.L LCO relating to system OPERABILITY (in this case the suppression pool spray function shall have two "independent" subsystems, each with a pump and flow path) is proposed to be relocated to the Bases. These details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. Therefore, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

"Specific"

None

RELOCATED SPECIFICATIONS

R.1 The requirement for drywell spray will be relocated to the Technical Requirements Manual (TRM). The drywell spray is not credited in DBA (i.e., it is not needed to function to mitigate the consequences of any design basis accidents). While it is assumed to be utilized in the emergency operating procedures, it has been determined to be non-risk significant. Therefore, the requirements specified for the drywell spray in CTS 3/4.7.L did not satisfy the NRC Policy Statement Technical Specification screening criteria as documented in the Application of Selection Criteria to the Quad Cities 1 and 2 Technical Specifications and will be relocated to the TRM, which is controlled in accordance with 10 CFR 50.59.

A.1

3.7 - LIMITING CONDITIONS FOR OPERATION

N. SECONDARY CONTAINMENT INTEGRITY

LCO 3.6.4.1 SECONDARY CONTAINMENT INTEGRITY OPERABLE shall be ~~maintained~~. A.2

APPLICABILITY:

OPERATIONAL MODE(s) 1, 2, 3 and *.

ACTION:

ACTION A A2 1. Without SECONDARY CONTAINMENT OPERABLE ~~INTEGRITY~~ in OPERATIONAL MODES(s) 1, 2 or 3, restore SECONDARY CONTAINMENT to OPERABLE status ~~INTEGRITY~~ within 4 hours or be in at

ACTION B least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION C A2 2. Without SECONDARY CONTAINMENT OPERABLE ~~INTEGRITY~~ in OPERATIONAL MODE *, suspend handling of irradiated fuel in the secondary containment, CORE ALTERATION(s), and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.C are not applicable.

4.7 - SURVEILLANCE REQUIREMENTS

N. SECONDARY CONTAINMENT INTEGRITY

SECONDARY CONTAINMENT ~~INTEGRITY~~ OPERABLE shall be demonstrated by:

SR 3.6.4.1.1 1. Verifying at least once per 24 hours that the pressure within the secondary containment is ≥0.10 inches of vacuum water gauge.

2. Verifying at least once per 31 days that: A.3

SR 3.6.4.1.2 a. At least one door in each secondary containment air lock is closed.

b. All secondary containment penetrations[a] not capable of being closed by OPERABLE secondary containment automatic isolation dampers and required to be closed during accident conditions are closed. Moved to ITS 3.6.4.2 A.4 LD.1

SR 3.6.4.1.3 3. At least once per ~~18~~ 24 months on a STAGGERED TEST BASES by operating one standby gas treatment subsystem at a flow rate ≤4000 cfm for one hour and maintaining ≥0.25 inches of vacuum water gauge in the secondary containment. M.1

add proposed SR 3.6.4.1.4 M.2 D

APPLICABILITY * When handling irradiated fuel in the secondary containment, during CORE ALTERATION(s), and operations with a potential for draining the reactor vessel.

a Valves and blind flanges in high-radiation areas may be verified by use of administrative controls. Normally locked or sealed-closed penetrations may be opened intermittently under administrative control. Moved to ITS 3.6.4.2 A.4

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 CTS 4.7.N.3 requires that one subsystem be tested every 18 months. However, the same SGT subsystem could be tested at each testing occurrence. Proposed SR 3.6.4.1.3 will now require both subsystems be tested in the course of 48 months, as represented by the Staggered Test Basis requirement of the 24 month Frequency. This will ensure each SGT subsystem can maintain the proper vacuum. This is an additional restriction on plant operation.

M.2 A new Surveillance is being added, ITS SR 3.6.4.1.4, which requires all secondary containment equipment hatches to be verified closed and sealed every 24 months. This SR provides adequate assurance that exfiltration from the secondary containment through these hatches will not occur.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LD.1 The Frequency for performing CTS 4.7.N.3 has been extended from 18 months to 24 months in proposed SR 3.6.4.1.3 to facilitate a change to the Quad Cities 1 and 2 refuel cycle from 18 months to 24 months. This surveillance ensures that the Secondary Containment is OPERABLE. The proposed change will allow this Surveillance to extend the Surveillance Frequency from the current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in CTS 4.0.B and proposed SR 3.0.2) to a 24 month Surveillance Frequency (i.e., a maximum of 30 months accounting for the allowable grace period specified in CTS 4.0.B and proposed Specification 3.0.2). This proposed change was evaluated in accordance with the guidance provided in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

CTS 4.7.N.3 (ITS SR 3.6.4.1.3) verifies the secondary containment can be maintained at the required vacuum. The purpose of this test is to ensure secondary containment boundary integrity by demonstrating that secondary containment vacuum assumed in the safety analysis can be maintained under design basis conditions. Extending the surveillance interval for this verification of secondary containment integrity is acceptable because secondary containment is maintained at a negative pressure during normal operation, and secondary containment structural integrity is maintained through administrative controls which ensure that no significant changes will be made to the secondary containment structure without proper evaluation. Furthermore, based on engineering judgement, any structural degradation which would result in

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) impacting secondary containment OPERABILITY is not likely to occur during normal plant operation. Any event which would cause significant structural degradation, such as a seismic event would require a plant evaluation.

Reviews of historical maintenance and surveillance data have shown that these tests normally pass their Surveillances at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be minimal. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) do not invalidate any assumptions in the plant licensing basis.

"Specific"

None

RELOCATED SPECIFICATIONS

None

<CTS>

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
<4.7.A.1> SR 3.6.1.1.1	Perform required visual examinations and leakage rate testing except for primary containment air lock testing, in accordance with ~~10 CFR 50, Appendix J, as modified by approved exemptions~~ the Primary Containment Leakage Rate Testing Program. ~~The leakage rate acceptance criterion is ≤ 1.0 L_a. However, during the first unit startup following testing performed in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, the leakage rate acceptance criteria are < 0.6 L_a for the Type B and Type C tests, and < 0.75 L_a for the Type A test.~~	~~-----NOTE----- SR 3.0.2 is not applicable --------------~~ In accordance ~~with 10 CFR 50, Appendix J, as modified by approved exemptions~~ the Primary Containment Leakage Rate Testing Program 1
<4.7.K.5> SR 3.6.1.1.2	Verify drywell to suppression chamber differential pressure ~~does not decrease at a rate > [0.25] inch water gauge per minute tested over a [10] minute period~~ is ≤ 2% of the acceptable $A/\sqrt{k}$ design value of 0.18 ft^2 3 at an initial differential pressure of ~~[1]~~ 1.0 psid. 3	~~[18]~~ 24 months 3 D **AND** -----NOTE----- Only required after two consecutive tests fail and continues until two consecutive tests pass -------------- ~~[6]~~ 12 months 3 C

C D

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1433, REVISION 1
ITS: 3.6.1.1 - PRIMARY CONTAINMENT

1. A 10 CFR 50 Appendix J Testing Program Plan has been added to Section 5.5. The program references the requirements of 10 CFR 50 Appendix J and approved exemptions, therefore, the surveillances have been modified to reference the program. This is consistent with Current Licensing Basis and with TSTF-52.

2. Not used.

3. The brackets have been removed and the proper plant specific values have been included.

<CTS>

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
<Doc L.3> B. ---------NOTE--------- Only applicable to penetration flow paths with two [or more] PCIVs. ------------------------------ [1] One or more penetration flow paths with two [or more] PCIVs inoperable ~~except for purge valve leakage not within limit~~ [9] [for reasons other than Condition [B] D [and E]] [1] TSTF-207	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. TSTF-207 [9]	1 hour
	[for reasons other than Condition [E] D [and E]] [1] TSTF-207	
<3.7.D Act 1> <3.7.D Act 2> <4.7.A.2> <4.7.A.2 footnote 6> C. ---------NOTE--------- Only applicable to penetration flow paths with only one PCIV. ------------------------------ One or more penetration flow paths with one PCIV inoperable.	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 valves (EFCVs) [and penetrations with a closed system] [4] [5] AND (72) ~~12~~ hours ~~for EFCVs~~ [5] [4] TSTF-207
	AND	
<Doc L.10> TSTF-269	C.2 ---------NOTE--------- (1.) Isolation devices in high radiation areas may be verified by use of administrative means. (5) 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ------------------------------ Verify the affected penetration flow path is isolated. TSTF-207	[4 hours for hydrostatically tested line leakage [not on a closed system] AND] [1] Once per 31 days [for secondary containment bypass leakage] [1]
<3.6.M Act> [One or more] [1] D. ~~[Secondary containment bypass leakage rate]~~ not within limit. [1] [9] [MSIV leakage rate,] [purge valve leakage rate,] [hydrostatically tested line leakage rate,] [or] [EFCV leakage rate] [1] TSTF-207	D.1 Restore leakage rate to within limit. [1]	~~[4 hours]~~ [1] [9] [11] AND 8 hours for MSIV leakage AND [24 hours for purge valve leakage] AND [72 hours for hydrostatically tested line leakage [on a closed system] [and EFCV leakage]] [1]

(continued)

L ⟨CTS⟩

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.12	---NOTES--- [1. Only required to be met in MODES 1, 2, and 3.] 2. Results shall be evaluated against acceptance criteria of SR 3.6.1.1.1 in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions. --- Verify the combined leakage rate for all secondary containment bypass leakage paths is ≤ [L_a] when pressurized to ≥ [psig].	---NOTE--- SR 3.0.2 is not applicable --- In accordance with 10 CFR 50, Appendix J, as modified by approved exemptions
SR 3.6.1.3.~~13~~ 46 10 1	Verify the combined leakage rate ~~through each~~ for all MSIV leakage paths is ≤ ~~[11.5]~~ scfh when tested at ≥ ~~[28.8]~~ 25 psig. 9 11	~~---NOTE--- SR 3.0.2 is not applicable ---~~ In accordance with ~~10 CFR 50, Appendix J, as modified by approved exemptions~~ the Primary Containment Leakage Rate Testing Program 10

⟨4.7.D.6⟩

1A

(continued)

<CTS>

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.4.1	Verify each RHR suppression pool spray subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	31 days
~~[SR 3.6.2.4.2~~	~~Verify each RHR pump develops a flow rate ≥ [400] gpm through the heat exchanger while operating in the suppression pool spray mode.~~	~~In accordance with the Inservice Testing Program or 92 days]~~
SR 3.6.2.4.2	Verify each suppression pool spray nozzle is unobstructed.	10 years

<4.7.L.1>

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<DOC M1>

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D

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1433, REVISION 1
ITS: 3.6.2.4 - RHR SUPPRESSION POOL SPRAY

1. The Quad Cities 1 and 2 design does not include an automatically actuated RHR Suppression Pool Spray System; the system is entirely manually actuated. Therefore, the word "automatic" has been deleted from the valve position check Surveillance (ITS SR 3.6.2.4.1).

2. Editorial change made to be consistent with other similar specifications.

3. The bracketed requirement has been deleted. The current licensing basis for Quad Cities 1 and 2 does not require a suppression pool spray flow rate verification.

4. A new Surveillance was added which verifies each suppression pool spray nozzle is unobstructed every 10 years. This Surveillance is required to ensure that when a suppression pool spray subsystem is required per its design function that it will perform as designed. If the spray nozzles are obstructed, then their design function may not be met.

<CTS>

ACTIONS

	CONDITION	REQUIRED ACTION	COMPLETION TIME
<3.7.N Act 2>	C. (continued)	C.2 Suspend CORE ALTERATIONS. AND C.3 Initiate action to suspend OPDRVs.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE		FREQUENCY	
<4.7.N.1>	SR 3.6.4.1.1	Verify ~~[secondary]~~ containment vacuum is ≥ ~~[0.25]~~ 0.10 inch of vacuum water gauge.	24 hours	1
	SR 3.6.4.1.~~2~~ 4 2	Verify all ~~[secondary]~~ 1 containment equipment hatches are closed and sealed.	~~31 days~~ 24 months	2
<4.7.N.2>	SR 3.6.4.1.~~3~~ 2 2	Verify ~~each~~ one ~~[secondary]~~ containment access door in each access opening is closed~~, except when the access opening is being used for entry and exit[, then at least one door shall be closed]~~. 1	31 days	TSTF-18
	SR 3.6.4.1.4	~~Verify each standby gas treatment (SGT) subsystem will draw down the [secondary] containment to ≥ [0.25] inch of vacuum water gauge in ≤ [120] seconds.~~	~~[18] months on a STAGGERED TEST BASIS~~	5

<Move to proper location>

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1433, REVISION 1
ITS: 3.6.4.1 - SECONDARY CONTAINMENT

1. The brackets have been removed and the proper plant specific information/value has been provided.

2. ISTS SR 3.6.4.1.2 verifies all secondary containment equipment hatches are closed and sealed every 31 days. The Surveillance Requirement was not added during the Technical Specification Upgrade Program, in accordance with Amendment 171 and 167 respectively, issued by the NRC on November 27, 1995. However, the SR will be added at a 24 month Frequency (ITS SR 3.6.4.1.4). The following requirements have been revised or renumbered, where applicable, to reflect this change.

3. Not used.

4. ISTS SR 3.6.1.4.5 is a test that ensures the Secondary Containment is Operable; the leak tightness of the Secondary Containment boundary is within the assumptions of the accident analyses. However, it is written in such a manner it implies that if a SGT subsystem is inoperable, the SR is failed ("Verify each standby gas treatment (SGT) subsystem can..."). As stated above, this is not the intent of the SR. Therefore, to ensure this misinterpretation cannot occur, the SR has been rephrased to more clearly convey the original intent of the SR, to verify the Secondary Containment is Operable. With the new wording, if a SGT subsystem is inoperable, ITS SR 3.6.4.1.3 will still be met and only the SGT System Specification, LCO 3.6.4.3, will be required to be entered. The SR will still ensure each SGT subsystem is used (on a STAGGERED TEST BASIS) to perform the SR. This change is also consistent with TSTF-322.

5. The bracketed Surveillance (ISTS SR 3.6.4.1.4), the drawdown test, has been deleted consistent with the current licensing basis. The analysis does not assume an explicit drawdown time. The subsequent SR has been renumbered to reflect this deletion.

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
⟨4.7.N.2.b⟩ ⟨4.7.N.2.b footnote a⟩ SR 3.6.4.2.1	-------------------NOTES------------------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. Not required to be met for SCIVs that are open under administrative controls. --- Verify each secondary containment isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed.	31 days 1 D TSTF-45 Rev.2
⟨DOC M.1⟩ SR 3.6.4.2.2 TSTF-46	Verify the isolation time of each power operated ~~and each~~ automatic SCIV is within limits.	[~~In accordance with the Inservice Testing Program or~~ 92 days] 1
⟨4.7.O.2⟩ SR 3.6.4.2.3	Verify each automatic SCIV actuates to the isolation position on an actual or simulated actuation signal.	~~[18]~~ 24 months 1

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

the Primary Containment Leakage Rate Testing Program

3

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of ~~10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions~~. Failure to meet air lock leakage ~~testing~~ limit (SR 3.6.1.2.1), ~~[secondary containment bypass leakage (SR 3.6.1.3.12),] [resilient seal primary containment purge valve leakage testing (SR 3.6.1.3.7),]~~ or main steam isolation valve leakage (SR 3.6.1.3.~~13~~ 10) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of ~~10 CFR 50, Appendix J, as modified by approved exemptions (Ref. 3)~~. As left leakage prior to the first startup after performing a required ~~10 CFR 50, Appendix J,~~ Primary Containment Leakage Rate Testing Program leakage test is required to be < 0.6 L_a for combined Type B and C leakage, and ~~<~~ ≤ 0.75 L_a for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the ~~10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.~~

3 6 3 10 # 6 1 3 3 3

SR 3.6.1.1.2

Maintaining the pressure suppression function of primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the downcomers into the suppression pool. This SR measures drywell to suppression chamber differential pressure during a ~~[10]~~ 15 minute period to ensure that the leakage paths that would bypass the suppression pool are within allowable limits.

4

Satisfactory performance of this SR can be achieved by establishing a known differential pressure (≥ 1.0 psid) between the drywell and the suppression chamber and verifying that the ~~pressure in either the suppression chamber or the drywell does not change by more than [0.25] inch of water per minute over a 10 minute period~~ measured bypass leakage is ≤ 2% of the acceptable A/√k design value of 0.18 ft². The leakage test is performed every ~~[18~~ 24 months~~]~~. The ~~[18~~ 24 month~~]~~ Frequency was developed

1 1 4 D

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.2 (continued)

considering it is prudent that this Surveillance be performed during a unit outage and also in view of the fact that component failures that might have affected this test are identified by other primary containment SRs. Two consecutive test failures, however, would indicate unexpected primary containment degradation; in this event, as the Note indicates, increasing the Frequency to once every ~~[9]~~ 12 months is required until the situation is remedied as evidenced by passing two consecutive tests.

REFERENCES

1. U FSAR, Section ~~[6.2]~~ .1.
2. FSAR, Section ~~[15.1.39]~~ 15.6.5.
3. 10 CFR 50, Appendix J, Option B.

All changes are [1] unless otherwise indicated

Low Set Relief

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Low-Low Set (LLS) Valves

Relief

[2] In addition, one relief valve is designed to open in the safety mode. (However, for the purposes of this LCO, only the low set relief mode of the relief valves is required)

BASES

relief

low set relief

disc

Insert BKGD-1

will

partially

spring

main

Insert BKGD-2

BACKGROUND

The ~~safety~~/relief valves (S/RVs) can actuate in either the ~~safety~~ mode, ~~the Automatic Depressurization System mode,~~ or the LLS mode. ~~In the LLS mode (or power actuated mode of operation), a pneumatic diaphragm and stem assembly overcomes the spring force and opens the pilot valve. As in the safety mode, opening the pilot valve allows a differential pressure to develop across the main valve~~ [3] ~~piston and opens the main valve. The main valve can stay open with valve inlet steam pressure as low as 50 psig. Below this pressure, steam pressure may not be sufficient to hold the main valve open against the spring force of the pilot valve. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure exceeds the safety mode pressure setpoints.~~ [2]

However with inlet steam pressure below 150 psig

Fully

relief valves

low set relief setpoints

low set relief [2]

Two

[3]

other

valves

two

relief valves

relief valve

relief valve

low set relief

low set

~~Four~~ of the S/RVs are equipped to provide the LLS function. The LLS ~~logic~~ causes the LLS valves to be opened at a lower pressure than the relief ~~or safety mode pressure setpoints~~ and stay open longer, so that reopening more than ~~one~~ S/RV is prevented on subsequent actuations. Therefore, the LLS function prevents excessive short duration S/RV cycles with valve actuation at the relief setpoint.

Each S/RV discharges steam through a discharge line and quencher to a location near the bottom of the suppression pool, which causes a load on the suppression pool wall. Actuation at lower reactor pressure results in a lower load.

A time delay in the low set relief valve logic prevents actuation concurrent with an elevated water level in the discharge line.

[2] low set

no more than two relief valves

relief valves

[2]

low set relief

APPLICABLE SAFETY ANALYSES

The LLS relief mode functions to ensure that the containment design basis of ~~one S/RV~~ operating on "subsequent actuations" is met. In other words, multiple simultaneous openings of ~~S/RVs~~ (following the initial opening), and the corresponding higher loads, are avoided. The safety analysis demonstrates that the LLS functions to avoid the induced thrust loads on the S/RV discharge line resulting from "subsequent actuations" of the S/RV during Design Basis Accidents (DBAs). ~~Furthermore, the LLS function justifies the primary containment analysis assumption that~~

relief valve

(continued)

All changes are [1] unless otherwise indicated

BASES

BACKGROUND (continued)

Low spray temperatures and atmospheric conditions that yield the minimum amount of contained noncondensible gases are assumed for conservatism.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving the reactor building-to-suppression chamber vacuum breakers are presented in Reference 1 as part of the accident response of the containment systems. Internal (suppression-chamber-to-drywell) and external (reactor building-to-suppression chamber) vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls, which form part of the primary containment boundary.

The safety analyses assume the external vacuum breakers to be closed initially ~~and to be fully open at [0.5] psid (Ref. 1). Additionally, of the two reactor building-to-suppression chamber vacuum breakers, one is assumed to fail in a closed position to satisfy the single active failure criterion.~~ Insert 3.6.1.7 ASA Design Basis Accident (DBA) analyses ~~require~~ assume the vacuum breakers to be closed initially and ~~to~~ remain closed and leak tight with positive primary containment pressure. that at least one vacuum breaker on each line [5] [D]

~~Five~~ Four cases were considered in the safety analyses to determine the adequacy of the external vacuum breakers:

a. A small steam line break loss of coolant accident followed by actuation of ~~both~~ one ~~primary containment~~ drywell and suppression pool spray loop~~s~~;

b. ~~Inadvertent actuation of one primary containment spray loop during normal operation;~~ An intermediate steam line break loss of coolant accident followed by actuation of one drywell and suppression pool spray loop;

~~c. Inadvertent actuation of both primary containment spray loops during normal operation;~~ [C]

d. A postulated DBA assuming Emergency Core Cooling Systems (ECCS) runout flow with a ~~condensation effectiveness~~ thermal mixing efficiency of ~~50~~ 60%; and

e. A postulated DBA ~~assuming ECCS runout flow with a condensation effectiveness of 100%~~ followed by actuation of one drywell and suppression pool spray loop.

The results of these ~~five~~ four cases show that the external vacuum breakers, with an opening setpoint of ~~[0.5]~~ psid, are [2]

(continued)

1 Insert 3.6.1.7 ASA

, with the mechanical vacuum breakers counter balanced to open at 0.5 psid and to be fully open in one second. The air operated butterfly valve vacuum breakers are assumed to open concurrent with the mechanical vacuum breakers and be full open in one second (Ref. 2). Since only one of the two parallel 20 inch vacuum breaker lines is required to protect the suppression chamber from excessive negative differential pressure, the single active failure criterion is satisfied. 10

BASES

APPLICABLE SAFETY ANALYSES (continued)

capable of maintaining the differential pressure within design limits.

The reactor building-to-suppression chamber vacuum breakers satisfy Criterion 3 of ~~the NRC Policy Statement~~. 10 CFR 50.36 (c)(2)(ii) 1

LCO

All reactor building-to-suppression chamber vacuum breakers are required to be OPERABLE to satisfy the assumptions used in the safety analyses. The requirement ensures that the two vacuum breakers (mechanical vacuum breaker and air operated butterfly valve) in each of the two lines from the reactor building to the suppression chamber airspace are closed (except during testing or when performing their intended function). Also, the requirement ensures both vacuum breakers in each line will open to relieve a negative pressure in the suppression chamber. 1

APPLICABILITY 4

~~In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 1, 2, and 3, the Suppression Pool Spray System is required to be OPERABLE to mitigate the effects of a DBA.~~ Excessive negative pressure inside primary containment could occur due to inadvertent initiation of ~~this system. Therefore, the vacuum breakers are required to be OPERABLE in MODES 1, 2, and 3, when the Suppression Pool Spray System is required to be OPERABLE, to mitigate the effects of inadvertent actuation of the Suppression Pool Spray System.~~ drywell sprays. 1

4 ~~Also,~~ In MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture, which purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell, which, after the suppression chamber-to-drywell vacuum breakers open (due to excessive differential pressure between the suppression chamber and drywell), would result in depressurization of the suppression chamber. 1 The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3.

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining reactor

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1 (continued)

judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.

Two Notes are added to this SR. The first Note allows reactor-to-suppression chamber vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers. The second Note is included to clarify that vacuum breakers open due to an actual differential pressure are not considered as failing this SR.

SR 3.6.1.7.2

Each vacuum breaker must be cycled to ensure that it opens properly to perform its design function and returns to its fully closed position. This ensures that the safety analysis assumptions are valid. The [92] day Frequency of this SR was developed based upon Inservice Testing Program requirements to perform valve testing at least once every [92] days. 2

SR 3.6.1.7.3

Demonstration of vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of ≤ [0.5] psid is valid. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. For this unit, the [18] month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

2 24 2 24 plant 7

REFERENCES 1 ~~1~~. 4 [FSAR, Section [6.2]. 1.2.4.1 2

1 1. UFSAR, Sections 6.2.1.3.3 and 6.3.3.2.9.

BASES

ACTIONS

A.1 (continued)

However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment bypass mitigation capability. The 7 day Completion Time was chosen in light of the redundant RHR suppression pool spray capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

B.1

With both RHR suppression pool spray subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. In this ~~C~~ondition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to ~~remove heat from~~ primary containment are available. 2

1 reduce pressure in the

C.1 and C.2

any Required Action and

If ~~the inoperable RHR suppression pool spray 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 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. 2

met

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1

Verifying the correct alignment for manual, power operated, and ~~automatic~~ valves in the RHR suppression pool spray mode flow path provides assurance that the proper flow paths ~~will~~ exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A 3 2

(s)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1 (continued)

valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable since the RHR suppression pool ~~cooling~~ spray mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. 2

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the ~~sub~~system is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience. 4

SR 3.6.2.4.2

~~Verifying each RHR pump develops a flow rate ≥ [400] gpm while operating in the suppression pool spray mode with flow through the heat exchanger ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by Section XI of the ASME Code (Ref. 2). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is [in accordance with the Inservice Testing Program, but the Frequency must not exceed 92 days].~~ 3

This Surveillance is performed every 10 years to verify that the spray nozzles are not obstructed and that spray flow will be provided when required. The 10 year Frequency is adequate to detect degradation in performance due to the passive nozzle design and has been shown to be acceptable through operating experience.

REFERENCES

1. UFSAR, Section ~~[~~6.2~~]~~.2.2. 1 5

~~2. ASME, Boiler and Pressure Vessel Code, Section XI.~~ 3

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the [secondary] containment boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. The 24 hour Frequency of this SR was developed based on operating experience related to [secondary] containment vacuum variations during the applicable MODES and the low probability of a DBA occurring between surveillances.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal [secondary] containment vacuum condition.

TSTF-18

SR 3.6.4.1.2 and SR 3.6.4.1.3 4

Verifying that one [secondary] containment ~~equipment hatches and~~ access door~~s~~ ~~are~~ is closed in each access opening 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. In this application, the term "sealed" has no connotation of leak tightness. Maintaining [secondary] containment OPERABILITY requires verifying ~~each~~ one door in the access opening is closed, ~~except when the access opening is being used for normal transient entry and exit (then at least one door must remain closed)~~. The 31 day Frequency for ~~these~~ SR~~s~~ 3.6.4.1.2 has been shown to be adequate, based on operating experience, and is considered adequate in view of the other indications of door ~~and hatch~~ status that are available to the operator.

and each equipment hatch is closed and sealed

2 In addition, for equipment hatches that are floor plugs, the "sealed" requirement is effectively met by gravity.

Insert B 3.6.4.1.2

The 24 month Frequency for SR 3.6.4.1.4 is considered adequate in view of the existing administrative controls on equipment hatches.

TSTF-18

(continued)

All changes are 1 unless otherwise indicated

Each SGT subsystem is designed to maintain the secondary containment at ≥ 0.25 inches of vacuum water gauge for 1 hour at a flow rate of ≤ 4000 cfm.

BASES

SURVEILLANCE REQUIREMENTS (continued)

[SR 3.6.4.1.4 and SR 3.6.4.1.5] 1 3

The SGT System exhausts the [secondary] containment atmosphere to the environment through appropriate treatment equipment. To ensure that all fission products are treated, SR 3.6.4.1.4 verifies that the SGT System will rapidly establish and maintain a pressure in the [secondary] containment that is less than the lowest postulated pressure external to the [secondary] containment boundary. This is confirmed by demonstrating that one SGT subsystem will draw down the [secondary] containment to ≥ [0.25] inches of vacuum water gauge in ≤ [120] seconds. This cannot be accomplished if the [secondary] containment boundary is not intact. SR 3.6.4.1.5 demonstrates that one SGT subsystem can maintain ≥ [0.25] inches of vacuum water gauge for 1 hour at a flow rate ≤ [4000] cfm. 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, either SGT subsystem will perform this test. Operating experience has shown these components usually pass the Surveillance when performed at the [18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

released to secondary containment

can be maintained

When the SGT System is operating as designed, the maintenance of secondary containment pressure

5 the pressure in the secondary containment can be maintained

using one SGT subsystem

4

3 3

secondary containment boundary

24 es

REFERENCES

1. UFSAR, Section [15.1.39]. 15.6.5
2. UFSAR, Section [15.1.41]. 15.7.2

1

2

The inoperability of the SGT System does not necessarily constitute a failure of this Surveillance relative to secondary containment OPERABILITY.

5

used for this Surveillance is

5

The primary purpose of the SR is to ensure secondary containment boundary integrity. The secondary purpose of the SR is to ensure that the SGT subsytem being tested functions as designed. There is a separate LCO with Surveillance Requirements that serves the primary purpose of ensure OPERABILITY of the SGT System. This SR

<CTS>

4 Insert LCO

The following DGCW subsystems shall be OPERABLE:

<DOC M.1>

a. Two DGCW subsystems; and

b. The opposite unit DGCW subsystem capable of supporting its associated diesel generator (DG).

6 Insert B

B.	One or more unit DGCW subsystems inoperable and not capable of supporting the ECCS room emergency coolers.	B.1	Align a DGCW subsystem to the ECCS room emergency coolers.	1 hour
		<u>OR</u>		
		B.2	Declare associated ECCS inoperable.	1 hour

All changes are 2 unless otherwise noted

BASES (continued)

APPLICABILITY 1

In MODES 1, 2, and 3, the ~~[MCREC]~~ CREV System must be OPERABLE to control operator exposure during and following a DBA, since the DBA could lead to a fission product release.

In MODES 4 and 5, the probability and consequences of a DBA are reduced because of the pressure and temperature limitations in these MODES. Therefore, maintaining the ~~[MCREC]~~ CREV System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

4

~~a.~~ c. During operations with potential for draining the reactor vessel (OPDRVs)~~;~~.

b. During CORE ALTERATIONS; and

~~c.~~ a. During movement of irradiated fuel assemblies in the ~~[secondary]~~ containment~~.~~;

ACTIONS 1

A.1

With ~~one~~ the ~~[MCREC]~~ CREV ~~sub~~system inoperable in MODE 1, 2, or 3, the inoperable ~~[MCREC]~~ CREV ~~sub~~system must be restored to OPERABLE status within 7 days. ~~With the unit in this condition, the remaining OPERABLE [MCREC] subsystem is adequate to perform control room radiation protection. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced [MCREC] System capability.~~ The 7 day Completion Time is based on the low probability of a DBA occurring during this time period~~, and that the remaining subsystem can provide the required capabilities~~. 5 D

B.1 and B.2

1

In MODE 1, 2, or 3, if the inoperable ~~[MCREC]~~ CREV ~~sub~~system cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

SURVEILLANCE REQUIREMENTS

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

1. SR 3.8.1.1 through SR 3.8.1.20 are applicable only to the given unit's AC electrical power sources.

2. SR 3.8.1.21 is applicable to the opposite unit's AC electrical power sources.

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	7 days
SR 3.8.1.2	------------------NOTES------------------ 1. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 2. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.8 must be met. 3. A single test of the common DG at the specified Frequency will satisfy the Surveillance for both units. --- Verify each DG starts from standby conditions and achieves steady state voltage $\geq$ 3952 V and $\leq$ 4368 V and frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz.	31 days

(continued)

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.1.3	-------------------NOTES------------------ 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow, without shutdown, a successful performance of SR 3.8.1.2 or SR 3.8.1.8. 5. A single test of the common DG at the specified Frequency will satisfy the Surveillance for both units. -- Verify each DG is synchronized and loaded and operates for $\geq$ 60 minutes at a load $\geq$ 2340 kW and $\leq$ 2600 kW.	 31 days
SR 3.8.1.4	Verify each day tank contains $\geq$ 205 gal of fuel oil and each bulk fuel storage tank contains $\geq$ 10,000 gal of fuel oil.	31 days
SR 3.8.1.5	Remove accumulated water from each day tank.	31 days
SR 3.8.1.6	Verify each fuel oil transfer pump operates to automatically transfer fuel oil from the storage tank to the day tank.	31 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	-------------------NOTE------------------- All DG starts may be preceded by an engine prelube period. -- Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and: a. In $\leq$ 10 seconds after auto-start, achieves voltage $\geq$ 3952 V and frequency $\geq$ 58.8 Hz; b. Achieves steady state voltage $\geq$ 3952 V and $\leq$ 4368 V and frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz; and c. Operates for $\geq$ 5 minutes.	24 months
SR 3.8.1.14	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; and b. Generator differential current.	24 months

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources — Operating

LCO 3.8.4 The following DC electrical power subsystems shall be OPERABLE:

a. Two 250 VDC electrical power subsystems;

b. Division 1 and Division 2 125 VDC electrical power subsystems; and

c. The opposite unit's 125 VDC electrical power subsystem capable of supporting equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," LCO 3.7.4, "Control Room Emergency Ventilation (CREV) System" (Unit 2 only), LCO 3.7.5 "Control Room Emergency Ventilation Air Conditioning (AC) System" (Unit 2 only), and LCO 3.8.1, "AC Sources — Operating."

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One 250 VDC electrical power subsystem inoperable.	A.1 Restore the 250 VDC electrical power subsystem to OPERABLE status.	72 hours

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources — Shutdown

LCO 3.8.5 One 250 VDC and one 125 VDC electrical power subsystem shall be OPERABLE to support the 250 VDC and one 125 VDC Class 1E electrical power distribution subsystems required by LCO 3.8.8, "Distribution Systems — Shutdown."

APPLICABILITY: MODES 4 and 5,
During movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

-----NOTE-----
LCO 3.0.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DC electrical power subsystems inoperable.	A.1 Declare affected required feature(s) inoperable. OR A.2.1 Suspend CORE ALTERATIONS. AND A.2.2 Suspend movement of irradiated fuel assemblies in the secondary containment. AND	Immediately Immediately Immediately
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more DC electrical power distribution subsystems inoperable.	B.1 Restore DC electrical power distribution subsystems to OPERABLE status.	2 hours AND 16 hours from discovery of failure to meet LCO 3.8.7.a
C. One or more required opposite unit AC or DC electrical power distribution subsystems inoperable.	-------------NOTE------------ Enter applicable Condition and Required Actions of LCO 3.8.1 when Condition C results in the inoperability of a required offsite circuit. ---------------------------- C.1 Restore required opposite unit AC and DC electrical power distribution subsystems to OPERABLE status.	 7 days
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours
E. Two or more electrical power distribution subsystems inoperable that, in combination, result in a loss of function.	E.1 Enter LCO 3.0.3.	Immediately

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.8 (continued)

SR 3.8.1.8 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing and accepting a load approximately equivalent to that corresponding to the continuous rating. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0 when running synchronized with the grid. The 0.8 power factor value is the design rating of the machine at a particular kVA. The 1.0 power factor value is an operational condition where the reactive power component is zero, which minimizes the reactive heating of the generator. Operating the generator at a power factor between 0.8 lagging and 1.0 avoids adverse conditions associated with underexciting the generator and more closely represents the generator operating requirements when performing its safety function (running isolated on its associated 4160 V ESS bus). The 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 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 10).

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

A modified performance discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test when the modified performance discharge test is performed in lieu of the service test. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

For the 125 VDC battery, the acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 7) and IEEE-485 (Ref. 9). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating, since IEEE-485 (Ref. 9) recommends using an aging factor of 125% in the battery size calculation. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. However, since the 250 VDC batteries are not sized consistent with IEEE-485 (Ref. 9), they must be replaced when their actual capacity is below the minimum acceptable battery capacity based on the load profile, which is a value greater than 80% of the manufacturer's rating.

The Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, consistent with IEEE-450 (Ref. 7), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case Design Basis Accidents which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The DC electrical power subsystems — with: a) the required 250 VDC subsystem consisting of one 250 VDC battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus; and b) the required 125 VDC subsystem consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the

(continued)

BASES

LCO (continued)

associated bus — are required to be OPERABLE to support some of the required DC distribution subsystems required OPERABLE by LCO 3.8.8, "Distribution Systems — Shutdown." This requirement ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown). The associated alternate 125 VDC electrical power subsystem may be used to satisfy the requirements of the 125 VDC subsystem.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since irradiated fuel assembly movement can occur in MODE 1, 2, or 3, the ACTIONS have 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 irradiated fuel assemblies while in

(continued)

BACKGROUND (continued)

The 120 VAC essential services bus is supplied by a static uninterruptible power supply (UPS). Power to the UPS is supplied, in order of preference; for Unit 1 by 480 VAC bus 18, 250 VDC MCC 2, or 480 VAC bus 17; and for Unit 2 by 480 VAC bus 28, 250 VDC MCC 1, or 480 VAC bus 26. D

There are two independent 250 VDC station service electrical power distribution subsystems and two independent 125 VDC electrical power distribution subsystems that support the necessary power for ESF functions. The 250 VDC electrical power distribution subsystem provides motive power to large DC loads such as DC motor-driven pumps and valves. Division 1 and 2 125 VDC electrical power distribution subsystems provide control power to selected safety related equipment as well as circuit breaker control power for 4160 V, 480 V, control relays, and annunciators. The Division 2 125 VDC subsystem for each unit is provided power by the opposite unit's battery and provides control power to a shared standby gas treatment subsystem.

The list of required distribution buses for Unit 1 and Unit 2 is presented in Tables B 3.8.7-1 and B 3.8.7-2, respectively. C

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume ESF systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

The OPERABILITY of the AC and DC electrical power distribution subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining distribution systems OPERABLE during accident conditions in the event of:

(continued)

BASES

ACTIONS

B.1 (continued)

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC electrical power distribution subsystems is consistent with Regulatory Guide 1.93 (Ref. 3).

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, an AC electrical power distribution subsystem 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 DC electrical power distribution subsystem. At this time, an AC electrical power distribution subsystem could again become inoperable, and DC electrical power distribution 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 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 B was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet LCO 3.8.7.a indefinitely.

C.1

With one or more required opposite unit AC or DC electrical power distribution subsystems inoperable, the redundant required features of the standby gas treatment (SGT) subsystem may not function if a design basis event were to occur. In addition, Unit 1 and Unit 2 share the single train Control Room Emergency Ventilation (CREV) and the associated Air Conditioning (AC) System. Since these

(continued)

BASES

ACTIONS

C.1 (continued)

systems are powered only from Unit 1, an inoperable Unit 1 AC electrical power distribution subsystem could result in a loss of the CREV System and Control Room Emergency Ventilation AC System functions (for both units).

With a standby gas treatment (SGT) subsystem inoperable, LCO 3.6.4.3 requires restoration of the inoperable SGT subsystem to OPERABLE status in 7 days. Similarly, with the CREV System inoperable, LCO 3.7.4 requires restoration of the inoperable CREV System to OPERABLE status within 7 days. With the Control Room Emergency Ventilation AC System inoperable, LCO 3.7.5 requires restoration of the inoperable Control Room Emergency Ventilation AC System to OPERABLE status in 30 days. Therefore, a 7 day Completion Time is provided to restore the required opposite unit AC and DC electrical power subsystems to OPERABLE status. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant system(s) and the low probability of a DBA occurring during this time period.

The Required Action is modified by a Note indicating that the applicable Conditions of LCO 3.8.1 be entered and Required Actions taken if the inoperable opposite unit AC electrical power distribution subsystem results in an inoperable required offsite circuit. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

D.1 and D.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.

(continued)

Table B 3.8.7-1 (page 1 of 1)
Unit 1 AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1[a]	DIVISION 2[a][b]
AC safety bus	4160 V	ESS buses 13, 13-1	ESS buses 14, 14-1
	480 V	ESS bus 18	ESS bus 19
	120 V	Unit essential services bus, unit instrument bus	NA
250 VDC buses	250 V	NA	TB MCC 1, RB MCC 1A, RB MCC 1B
125 VDC buses	125 V	TB main buses 1A, 1A-1; RB distribution panel 1	TB main bus 2A; TB reserve buses 1B and 1B-1

(a) Each division of the AC and DC electrical power distribution systems is a subsystem. The 250 VDC buses constitute a single subsystem (Division 2).

(b) OPERABILITY requirements of the opposite unit's Division 1 and Division 2 AC and DC electrical power distribution systems require OPERABILITY of the 4160 VAC bus 24-1, 480 VAC bus 29, essential services 120 VAC bus (must be powered from 480 VAC bus 28, 250 VDC TB MCC 2, or 480 VAC MCC 28-2), and 125 VDC bus 2B.

Table B 3.8.7-2 (page 1 of 1)
Unit 2 AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1[a]	DIVISION 2[a][b]
AC safety bus	4160 V	ESS buses 23, 23-1	ESS bus 24, 24-1
	480 V	ESS bus 28	ESS bus 29
	120 V	Unit essential services bus, unit instrument bus	NA
250 VDC buses	250 V	NA	TB MCC 2, RB MCC 2A, RB MCC 2B
125 VDC buses	125 V	TB main bus 2A, 2A-1; RB distribution panel 2	TB main bus 1A; TB reserve buses 2B, 2B-1

(a) Each division of the AC and DC electrical power distribution systems is a subsystem. The 250 VDC buses constitute a single subsystem (Division 2).

(b) OPERABILITY requirements of the opposite unit's Division 1 and Division 2 AC and DC electrical power distribution systems require OPERABILITY of the 4160 VAC bus 14-1, 480 VAC bus 19, essential services 120 VAC bus (must be powered from 480 VAC bus 18, 250 VDC TB MCC 1, or 480 VAC MCC 18-2), and 125 VDC bus 1B.

3.9 - LIMITING CONDITIONS FOR OPERATION

D. D.C. Sources - Shutdown

LCO 3.8.5

~~As a minimum, the following D.C~~ electrical power sources shall be OPERABLE:

1. ~~One station 250 volt battery with a full capacity charger.~~
2. ~~One station 125 volt battery with a full capacity charger.~~

LA.1 One 250 VDC and one 125 VDC

to support the 250 VDC and one 125 VDC Class 1E electrical power distribution subsystems required by LCO 3.8.8, "Distribution Systems – Shutdown." M.1

APPLICABILITY:

OPERATIONAL MODE(s) 4 and 5, and when handling irradiated fuel in the secondary containment.

ACTION:

M.2 add proposed ACTIONS Note

ACTION A

With any of the above required station batteries and/or associated charger(s) inoperable, suspend CORE ALTERATIONS, suspend handling of irradiated fuel in the secondary containment, and suspend operations with a potential for draining the reactor vessel.

L.2 add proposed Required Action A.1

M.3 add proposed Required Actions A.2.4

4.9 - SURVEILLANCE REQUIREMENTS

L.1

D. D.C. Sources - Shutdown add proposed Note

SR 3.8.5.1

The required batteries and chargers shall be demonstrated OPERABLE[a] per the surveillance requirements in Specification 4.9.C. LA.2

C

D

C

LA.2

a ~~An alternate 125 volt battery shall adhere to these same Surveillance Requirements to be considered OPERABLE.~~

ADMINISTRATIVE

A.1 In the conversion of the Quad Cities 1 and 2 current Technical Specifications (CTS) to the proposed plant specific Improved Technical Specifications (ITS), certain wording preferences or conventions are adopted that do not result in technical changes (either actual or interpretational). Editorial changes, reformatting, and revised numbering are adopted to make the ITS consistent with the BWR Standard Technical Specifications, NUREG-1433, Rev. 1 (i.e., the Improved Standard Technical Specifications (ISTS)).

A.2 The ITS present the battery hardware components (battery and charger) in the DC Sources LCO (ITS 3.8.5). The battery cell parameters are presented in a separate LCO (ITS 3.8.6).

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The existing requirement of CTS 3.9.D for one 250 VDC and one 125 VDC electrical power sources to be OPERABLE during shutdown conditions is not specific as to what the sources must be powering. The requirement in ITS LCO 3.8.5 specifies that the sources must support an associated division of the onsite Class 1E DC Electrical Power Distribution System required by LCO 3.8.8, "Distribution Systems — Shutdown." This added restriction conservatively assures that at least the 250 VDC and one 125 VDC electrical power distribution subsystems have an OPERABLE DC source (battery and associated charger) supplying it with power, when required. D

M.2 CTS 3.9.D, "DC Sources — Shutdown" Actions have been modified by a Note stating that LCO 3.0.3 is not applicable (ITS 3.8.5 ACTIONS Note). If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. This clarification is necessary because defaulting to LCO 3.0.3 during irradiated fuel assembly movement in MODE 1, 2, or 3 would require the reactor to be shutdown, but would not require suspension of movement of irradiated fuel assemblies. Therefore, the proposed Note ensures that proper actions are taken when moving irradiated fuel assemblies in MODE 1, 2, or 3 (i.e., LCO 3.0.3 is not applicable and cannot be used in lieu of suspending fuel movement as required by the ACTIONS of the LCO). This change is also consistent with TSTF-36, Rev. 3.

M.3 In the event the necessary DC sources are not OPERABLE, plant conditions are conservatively restricted in CTS 3.9.D Action (ITS 3.8.5 Required Actions A.2.1, A.2.2, and A.2.3) by suspending CORE ALTERATIONS, irradiated fuel handling, and OPDRVs. However, continued operation without the necessary

TECHNICAL CHANGES - MORE RESTRICTIVE

M.3 (cont'd) DC sources should not be considered acceptable. Therefore, ITS 3.8.5 Required Action A.2.4 is added to commence and continue attempts to restore the necessary DC sources. (Note that if actions are taken in accordance with ITS 3.8.5 Required Action A.1, sufficiently conservative measures are assured by the ACTIONS for the individual components declared inoperable without requiring the efforts to restore the inoperable source.) ITS 3.8.5 Required Action results in an action which does not allow continued operation in the existing plant condition. This has the effect of not allowing MODE changes per LCO 3.0.4. Therefore this existing implicit requirement is explicitly addressed in the ITS 3.8.5 ACTIONS.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details relating to system OPERABILITY in CTS 3.9.D (what constitutes a required DC electrical power source) are proposed to be relocated to the Bases. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. ITS LCO 3.8.5 will still require one 250 VDC and one 125 VDC electrical power subsystem to be OPERABLE. Therefore, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.2 The detail of CTS 4.9.D footnote a that an alternate 125 volt battery shall adhere to these same Surveillance Requirements to be considered OPERABLE is proposed to be relocated to the Bases, in the form of a discussion that states the alternate 125 VDC battery can be used to meet the requirements of the LCO. This requirement is not necessary to ensure the OPERABILITY of the alternate batteries. This requirement, the definition of OPERABILITY, and the proposed Surveillances are sufficient to ensure that the requirement will be met. As such, the relocated detail is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 Three of the DC sources Surveillances required to be performed by CTS 4.9.D (CTS 4.9.C.4, 4.9.C.5, and 4.9.C.6) involve tests that would cause the only required OPERABLE 250 VDC battery to be rendered inoperable. This condition presents a significant risk if an event were to occur during the test. The NRC has previously provided Surveillance exceptions in the Quad Cities 1 and 2 CTS to avoid a similar condition for the AC sources, but the exceptions have not been applied to DC sources. In an effort to consistently address this concern, proposed SR 3.8.5.1 has a Note that excludes performance requirements of Surveillances that would require the required OPERABLE 250 VDC battery to be rendered inoperable. This allowance does not take exception to the requirement for the battery to be capable of performing the particular function - just to the requirement to demonstrate that capability while that source of power is being relied on to support meeting the LCO.

L.2 An alternative is proposed in the Quad Cities 1 and 2 ITS to suspending operations if a DC Source is inoperable, and movement of irradiated fuel assemblies, CORE ALTERATIONS, or OPDRVs are being conducted. The alternative, ITS 3.8.5 Required Action A.1, is to declare the affected feature(s) inoperable, and continue to conduct operations (e.g., OPDRVs), if the affected feature(s) ACTIONS allow. Conservative actions can be assured if the affected feature(s) without the necessary DC power is declared inoperable and the associated ACTIONS of the individual feature(s) taken. These conservative actions are current approved (or will be approved by the ITS amendment) by the NRC. Therefore, this change is considered acceptable.

RELOCATED SPECIFICATIONS

None

<CTS>

3 Insert SR Notes

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

<DOC M.1>

1. SR 3.8.1.1 through SR 3.8.1.20 are applicable only to the given unit's AC electrical power sources.

2. SR 3.8.1.21 is applicable to the opposite unit's AC electrical power sources.

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE		FREQUENCY
<3.9.A footnote a> <3.9.A footnote d> <DOC M.3> <DOC A.4>	SR 3.8.1.3	-----NOTES----- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow, without shutdown, a successful performance of SR 3.8.1.2 or SR 3.8.1.~~7~~ 8 [8] [7] 5. A single test of the common DG at the specified Frequency will satisfy the Surveillance for both units. ------------	
<4.9.A.2.d>		Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ ~~{1710}~~ 2340 kW and ≤ ~~{2000}~~ 2600 kW. [1]	31 days [6] ~~As specified in Table 3.8.1-1~~
<4.9.A.2> <4.9.A.2.a> <LCO 3.9.A.2.a> <LCO 3.9.A.2.b>	SR 3.8.1.4	Verify each day tank ~~[and engine mounted tank]~~ [2] contain~~{s}~~ [1] ≥ ~~{900}~~ 205 [1] gal of fuel oil and each bulk fuel storage tank contains ≥ 10,000 gal of fuel oil [8].	31 days
<4.9.A.3>	SR 3.8.1.5	~~Check for and~~ [8] remove accumulated water from each day tank ~~[and engine mounted tank]~~ [2].	~~{31}~~ [1] days
<4.9.A.2> <4.9.A.2.b>	SR 3.8.1.6	Verify ~~the~~ each [9] fuel oil transfer ~~system~~ [1] pump [9] operates to ~~{automatically}~~ transfer fuel oil from the [2] storage tank~~[s]~~ to the day tank ~~[and engine mounted tank]~~ [2].	~~{92}~~ 31 [1] days

[8] Insert SR 3.8.1.7

(continued)

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12 13	-------------------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] 10 seconds after auto-start and during tests, achieves voltage ≥ [3740] 3952 V and ≤ [4580] V; frequency ≥ [58.8] Hz b. In ≤ [12] seconds after auto-start and during tests, achieves frequency ≥ [58.8] Hz and ≤ [61.2] Hz; and steady state voltage ≥ [3740] 3952 V and ≤ [4580] 4368 V and c. Operates for ≥ [5] minutes; d. Permanently connected loads remain energized from the offsite power system; and e. Emergency loads are energized [or auto-connected through the automatic load sequencer] from the offsite power system.	[18 months] 24

(continued)

<4.9.A.8.e>

<3.9.A footnote a>

8 10 11 18 TSTF-163 D C

<CTS>

$\boxed{1}$ Insert LCO 3.8.4

<LCO 3.9.C.1> a. Two 250 VDC electrical power subsystems;

<LCO 3.9.C.2> b. Division 1 and Division 2 125 VDC electrical power subsystems; and

<DOC M.2> c. The opposite unit's 125 VDC electrical power subsystem capable of supporting equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," LCO 3.7.4, "Control Room Emergency Ventilation (CREV) System" (Unit 2 only), LCO 3.7.5, "Control Room Emergency Ventilation Air Conditioning (AC) System" (Unit 2 only), and LCO 3.8.1, "AC Sources—Operating."

Insert ACTIONS

<3.9.2 footnote b> B. --------NOTE-------- Only applicable if opposite unit is in MODE 1, 2, or 3. -------------------- <3.9.2 Action 2> Division 1 or 2 125 VDC battery inoperable as a result of maintenance or testing.	B.1 Place associated OPERABLE alternate 125 VDC electrical power subsystem in service. <u>AND</u> B.2 Restore Division 1 or 2 125 VDC battery to OPERABLE status.	72 hours Prior to exceeding 7 cumulative days per operating cycle of battery inoperability, on a per battery basis, as a result of maintenance or testing

<CTS>

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources—Shutdown

<LCO 3.9.D>

LCO 3.8.5 [DC electrical power subsystems shall be OPERABLE to support the DC electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems—Shutdown."] TSTF-204

2 [One 250 VDC and one 125 VDC electrical power subsystem shall be OPERABLE] to support the 250 VDC and one 125 VDC Class 1E electrical power distribution subsystems required by LCO 3.8.8, "Distribution Systems—Shutdown." 7

<Appl. 3.9.D>

APPLICABILITY: MODES 4 and 5,
During movement of irradiated fuel assemblies in the [secondary] containment. 2

------NOTE------
LCO 3.0.3 is not applicable. 3

<DOC M.2>

ACTIONS

<3.9.D Action>

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One [or more] required DC electrical power subsystem[s] inoperable. 2 TSTF-204	A.1 Declare affected required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies in the [secondary] containment. 2	Immediately
	AND	
		(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1433, REVISION 1
ITS: 3.8.5 - DC SOURCES — SHUTDOWN

1. The proper LCO number has been provided. This change was necessary due to the deletion of ISTS 3.8.7, "Inverters — Operating" and ISTS 3.8.8, "Inverters — Shutdown."

2. The brackets have been removed and the proper plant specific information/value has been provided.

3. The ACTIONS have 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 irradiated fuel assemblies while in Mode 1, 2, or 3, the fuel movement is independent of reactor operations. This clarification is necessary because defaulting to LCO 3.0.3 during irradiated fuel assembly movement in Mode 1, 2, or 3 would require the reactor to be shutdown, but would not require suspension of movement of irradiated fuel assemblies. Therefore, the proposed Note ensures that proper actions are taken when moving irradiated fuel assemblies in Mode 1, 2, or 3 (i.e., LCO 3.0.3 is not applicable and cannot be used in lieu of suspending fuel movement as required by the ACTIONS of the LCO). This change is also consistent with TSTF-36, Rev. 4.

4. Due to the Quad Cities 1 and 2 design (spare battery and charger for the 125 VDC Electrical Power System), individual batteries and battery chargers can be tested without compromising compliance with the requirements of the LCO. Therefore, since the test can be performed without compromising the DC loads, the SRs are not excepted from performance for the 125 VDC electrical power subsystem when the unit is shutdown (per the Note to SR 3.8.5.1). C

5. Editorial change made to match the words in the LCO and ACTION requirements.

6. Change made to be consistent with the Writers Guide.

7. The ISTS LCO, as modified by TSTF-204, is not specific as to what the DC sources must be powering. The LCO has been modified to require each DC source to be powering a DC division required OPERABLE by LCO 3.8.8. D

<CTS>

2

Insert LCO 3.8.7

The following electrical power distribution subsystems shall be OPERABLE:

<LCO3.9.E.1> a. Division 1 and Division 2 AC and DC electrical power distribution subsystems; and
<LCO3.9.E.2>

<DOC M.3> b. The portions of the opposite unit's AC and DC electrical power distribution subsystems necessary to support equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas treatment (SGT) System," LCO 3.7.4, "Control Room Emergency Ventilation (CREV) System" (Unit 2 only), LCO 3.7.5, "Control Room Emergency Ventilation Air Conditioning (AC) System" (Unit 2 only), and LCO 3.8.1, "AC Sources — Operating."

C

6

Insert 3.8.7 ACTION C

C

<DOC M.3> C. One or more required opposite unit AC or DC electrical power distribution subsystems inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.1 when Condition C results in the inoperability of a required offsite circuit. ---------------------------- C.1 Restore required opposite unit AC and DC electrical power distribution subsystems to OPERABLE status.	7 days

D
C
C

All changes are [1] unless otherwise identified

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.~~7~~ 8 (continued) [5]

SR 3.8.1.~~7~~ requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within ~~12~~ 10 seconds. The ~~12~~ second start requirement supports the assumptions in the design basis LOCA analysis of ~~FSAR, Section [6.3]~~ (Ref. ~~12~~) 14. The ~~12~~ second start requirement is not applicable to SR 3.8.1.2 (see Note ~~3~~ 2 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the ~~12~~ 10 second start requirement of SR 3.8.1.~~7~~ 8 applies. [5] [2] u [TSTF -253]

Since SR 3.8.1.~~7~~ 8 does require a ~~12~~ 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. ~~This procedure is the intent of Note 1 of SR 3.8.1.2.~~ [TSTF -163]

INSERT SR 3.8.1.2-1

INSERT SR 3.8.1.2-2

The ~~normal~~ 31 day Frequency for SR 3.8.1.2 ~~(see Table 3.8.1-1, "Diesel Generator Test Schedule")~~ is consistent with Regulatory Guide 1.9 (Ref. ~~3~~) 10. The 184 day Frequency for SR 3.8.1.~~7~~ 8 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing. [5] [5] | △

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing and accepting ~~greater than or equal to the equivalent of the maximum expected accident loads~~ a load approximately equivalent to that corresponding to the continuous rating. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated when running synchronized with the grid at a power factor between ~~[0.8 lagging]~~ and ~~[1.0]~~. The ~~[0.8]~~ value is the design rating of the machine, ~~while [1.0] is an operational limitation [to ensure circulating currents are minimized]~~ at a particular KVA. The 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. Power factor [3] [2] The Power factor value [3]

INSERT SR 3.8.1.3-1

(continued)

BASES

and SR 3.8.1.7 5

SURVEILLANCE REQUIREMENTS 1

SR 3.8.1.5 (continued)

This is accomplished by draining a portion of the contents from the bottom of the day tank to the top of the storage tank. Checking for and removal of any accumulated water from the bulk storage tank once every 92 days also eliminates the necessary environment for bacterial survival.

fuel oil and cause fouling, but all must have a water environment in order to survive. 6 Removal of water from the fuel oil day ~~[and engine mounted]~~ tanks once every ~~[31]~~ days 2 eliminates the necessary environment for bacterial survival. 1 This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. ~~10~~ 12 1). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each ~~required~~ 1 fuel oil transfer pump operates and automatically 5 transfers fuel oil from its associated storage tank to its associated day tank. It is required to support continuous operation of standby power sources. This Surveillance provides assurance that ~~the~~ each 1 fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The Frequency for this SR is consistent with the Frequency for testing the DGs in SR 3.8.1.3. DG operation for SR 3.8.1.3 is normally long enough that fuel oil level in the day tank will be reduced to the point where the fuel oil transfer pump automatically starts to restore fuel oil level by transferring oil from the storage tank.

~~[The Frequency for this SR is variable, depending on individual system design, with up to a [92] day interval. The [92] day Frequency corresponds to the testing requirements for pumps as contained in the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 13); however, the design of fuel transfer systems is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day [and engine mounted] tanks during or following DG testing. In such a case, a 31 day Frequency is appropriate. Since proper operation of fuel transfer systems is an inherent]~~ 2

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

~~Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:~~

~~a. Performance of the SR will not render any safety system or component inoperable;~~

~~b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and~~

~~c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.~~

13

5

SR 3.8.1.~~10~~ 11

1 Consistant with Regulatory Guide 1.9 (Ref.10), paragraph C.2.2.8,

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 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 ≤ [0.9]. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.~~

5 a load band (90% to 100%) has been specified based on Regulatory Guide 1.9 (Ref.10)

D

(continued)

BASES (continued)

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment to provide assurance that:

a. Systems providing adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.

ACTIONS

Insert ACTIONS NOTE [7]

A.1

An offsite circuit is considered inoperable if it is not available to one required ~~ESF division~~ 4160 V ESS bus [2] [8] [4]. If two or more ~~ESF~~ [2] ~~4.16 kV~~ 4160 V ESS [2] buses are required per LCO 3.8.10, one division with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By the allowance of the option to declare required features inoperable ~~with no~~ that are not powered from [8] offsite power ~~available~~, appropriate restrictions can be implemented in accordance with the ~~affected~~ required [9] required feature(s) LCOs' ACTIONS. [8]

Required features remaining powered from a qualified offsite circuit, even if that circuit is considered inoperable because it is not powering other required features, are not declared inoperable by this Required Action. For example, if both Division 1 and 2 ESS buses are required OPERABLE by LCO 3.8.8, and only the Division 1 ESS buses are not capable of being powered from offsite power, then only the required features powered from Division 1 ESS buses are required to be declared inoperable.

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

With the offsite circuit not available to all required divisions, the option still exists to declare all required features inoperable per Required Action A.1 [8]. Since this option may involve undesired administrative efforts, the allowance for

(continued)

BASES

SURVEILLANCE REQUIREMENTS

~~SR 3.8.4.7 (continued)~~

~~challenge safety systems.~~ Credit may be taken for unplanned events that satisfy the Surveillance. 5 9

TSTF-8 not adopted

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

10 Insert from SR 3.8.4.7

A battery modified performance discharge test is ~~described in the Bases for SR 3.8.4.7~~. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

For the 125 VDC battery, 1

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 7) and IEEE-485 (Ref. ~~10~~ 9). 1 These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating, since IEEE-485 (Ref. 9) recommends using an aging factor of 125% in the battery size calculation. 1 A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

However, since the 250 VDC batteries are not sized consistent with IEEE-485 (Ref. 9), they must be replaced when their actual capacity is below the minimum acceptable battery capacity based on the load profile, which is a value greater than 80% of the manufacturer's rating. 5 1

The Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, ~~according to~~ consistent with 2 IEEE-450 (Ref. 7), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is 10% below the manufacturer's rating. ~~All these~~ The 12 month and 60 month 1 Frequencies are consistent with the recommendations in IEEE-450 (Ref. 7). The 24 month Frequency is derived from the recommendations of IEEE-450 (Ref. 7) 1

1

(continued)

C D

TSTF-204 2 required the required 2

3 supplying power to the associated bus

BASES

some of the 2

LCO (continued)

equipment and interconnecting cabling; and (2) each DG DC subsystem consisting of one battery bank, one battery charger, and the corresponding control equipment and interconnecting cabling ~~are~~ required to be OPERABLE to support required DC distribution subsystems required OPERABLE by LCO 3.8.10, "Distribution Systems—Shutdown." This requirement ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).

125 VDC 1 3 b 2 is TSTF-204 and 2 4 8

Insert LCO 1

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

ACTIONS

Insert ACTIONS NOTE 5

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

TSTF-204 2

~~If more than one DC distribution subsystem is required according to LCO 3.8.10, the DC subsystems remaining OPERABLE with one or more DC power sources inoperable may be~~

(continued)

2 Insert BKGD-1

During normal operation, each subsystem's ESS buses are connected such that power is supplied to the Division 2 4160 V loads from the unit's main generator through a unit auxiliary transformer (UAT) and from the 345 kV system through the reserve auxiliary transformer (RAT) to supply the Division 1 4160 V loads. The UAT and RAT are connected in a normal – alternate power source arrangement for each of the 4160 V divisions (i.e., the RAT provides alternate power for the Division 2 ESS buses and the UAT for the Division 1 ESS buses).

2 Insert BKGD-2

The 120 VAC instrument bus is normally powered from 480 VAC bus 18-2 for Unit 1 and 480 VAC MCC 28-2 for Unit 2. The alternate power supply for the Unit 1 120 VAC instrument bus is supplied from 480 VAC MCC 15-2 and the Unit 2 120 VAC instrument bus is supplied from 480 VAC MCC 25-2. On a loss of normal power to the instrument bus an automatic bus transfer (ABT) switches to the alternate supply and automatically switches back to the normal supply when the normal supply is restored. However, the instrument bus ABT is only provided for reliability and is not required to be OPERABLE (i.e., only one power source to the instrument bus is required). C C

The 120 VAC essential services bus is supplied by a static uninterruptible power supply (UPS). Power to the UPS is supplied, in order of preference; for Unit 1 by 480 VAC bus 18, 250 VDC MCC 2, or 480 VAC bus 17; and for Unit 2 by 480 VAC bus 28, 250 VDC MCC 1, or 480 VAC bus 26. D

2 Insert BKGD-3

The 250 VDC electrical power distribution subsystem provides motive power to large DC loads such as DC motor-driven pumps and valves. Division 1 and 2 125 VDC electrical power distribution subsystems provide control power to selected safety related equipment as well as circuit breaker control power for 4160 V, 480 V, control relays, and annunciators. The Division 2 125 VDC subsystem for each unit is provided power by the opposite unit's battery and provides control power to a shared standby gas treatment subsystem.

1

Insert B 3.8.7 ACTION C

C.1

With one or more required opposite unit AC or DC electrical power distribution subsystems inoperable, the redundant required features of the standby gas treatment (SGT) subsystem may not function if a design basis event were to occur. In addition, Unit 1 and Unit 2 share the single train Control Room Emergency Ventilation (CREV) and the associated Air Conditioning (AC) System. Since these systems are powered only from Unit 1, an inoperable Unit 1 AC electrical power distribution subsystem could result in a loss of the CREV System and Control Room Emergency Ventilation AC System functions (for both units).

With a standby gas treatment (SGT) subsystem inoperable, LCO 3.6.4.3 requires restoration of the inoperable SGT subsystem to OPERABLE status in 7 days. Similarly, with the CREV System inoperable, LCO 3.7.4 requires restoration of the inoperable CREV System to OPERABLE status within 7 days. With the Control Room Emergency Ventilation AC System inoperable, LCO 3.7.5 requires restoration of the inoperable Control Room Emergency Ventilation AC System to OPERABLE status in 30 days. Therefore, a 7 day Completion Time is provided to restore the required opposite unit AC and DC electrical power subsystems to OPERABLE status. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant system(s) and the low probability of a DBA occurring during this time period.

The Required Action is modified by a Note indicating that the applicable Conditions of LCO 3.8.1 be entered and Required Actions taken if the inoperable opposite unit AC electrical power distribution subsystem results in an inoperable required offsite circuit. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

9

Insert B 3.8-88

Table B 3.8.7-1 (page 1 of 1)
Unit 1 AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1[a]	DIVISION 2[a][b]
AC safety bus	4160 V	ESS buses 13, 13-1	ESS buses 14, 14-1
	480 V	ESS bus 18	ESS bus 19
	120 V	Unit essential services bus, unit instrument bus	NA
250 VDC buses	250 V	NA	TB MCC 1, RB MCC 1A, RB MCC 1B
125 VDC buses	125 V	TB main buses 1A, 1A-1; RB distribution panel 1	TB main bus 2A; TB reserve buses 1B and 1B-1

(a) Each division of the AC and DC electrical power distribution systems is a subsystem. The 250 VDC buses constitute a single subsystem (Division 2)

(b) OPERABILITY requirements of the opposite unit's Division 1 and Division 2 AC and DC electrical power distribution systems require OPERABILITY of the 4160 VAC bus 24-1, 480 VAC bus 29, essential services 120 VAC bus (must be powered from 480 VAC bus 28, 250 VDC TB MCC 2, or 480 VAC MCC 28-2), and 125 VDC bus 2B.

Insert B 3.8-88 (continued)

Table B 3.8.7-2 (page 1 of 1)
Unit 2 AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1[a]	DIVISION 2[a][b]
AC safety bus	4160 V	ESS buses 23, 23-1	ESS bus 24, 24-1
	480 V	ESS bus 28	ESS bus 29
	120 V	Unit essential services bus, unit instrument bus	NA
250 VDC buses	250 V	NA	TB MCC 2, RB MCC 2A, RB MCC 2B
125 VDC buses	125 V	TB main bus 2A, 2A-1; RB distribution panel 2	TB main bus 1A; TB reserve buses 2B, 2B-1

(a) Each division of the AC and DC electrical power distribution systems is a subsystem. The 250 VDC buses constitute a single subsystem (Division 2)

(b) OPERABILITY requirements of the opposite unit's Division 1 and Division 2 AC and DC electrical power distribution systems require OPERABILITY of the 4160 VAC bus 14-1, 480 VAC bus 19, essential services 120 VAC bus (must be powered from 480 VAC bus 18, 250 VDC TB MCC 1, or 480 VAC MCC 18-2), and 125 VDC bus 1B.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1433, REVISION 1
ITS: 3.9.1 - REFUELING EQUIPMENT INTERLOCKS

1. The current wording of ISTS 3.9.1 and the associated Applicability could imply that all the refueling equipment interlocks are required at all times during in-vessel fuel movement. The Current Licensing Basis only requires the interlocks associated with the refuel position, not those associated with other positions of the reactor mode switch, and only when the reactor mode switch is in the refuel position, not when it is in the shutdown position. Therefore, to avoid confusion, the LCO and Applicability have been modified to specifically state that the refueling interlocks are those associated with the refuel position, and that it is applicable when the reactor mode switch is in the refuel position. This change is also consistent with TSTF-232.

2. The brackets have been removed and the proper plant specific information/value has been provided.

3. The bracketed requirement has been deleted because it is not applicable to Quad Cities 1 and 2.

4. Changes have been made consistent with proposed TSTF-225, Revision 1.

3.10 SPECIAL OPERATIONS

3.10.3 Single Control Rod Withdrawal — Cold Shutdown

LCO 3.10.3 The reactor mode switch position specified in Table 1.1-1 for MODE 4 may be changed to include the refuel position, and operation considered not to be in MODE 2, to allow withdrawal of a single control rod, and subsequent removal of the associated control rod drive (CRD) if desired, provided the following requirements are met:

a. All other control rods are fully inserted;

b. 1. LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," and

LCO 3.9.4, "Control Rod Position Indication,"

<u>OR</u>

2. A control rod withdrawal block is inserted; and

c. 1. LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," MODE 5 requirements for Functions 1.a, 1.b, 7.a, 7.b, 11, and 12 of Table 3.3.1.1-1,

LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," MODE 5 requirements, and

LCO 3.9.5, "Control Rod OPERABILITY — Refueling,"

<u>OR</u>

2. All other control rods in a five by five array centered on the control rod being withdrawn are disarmed; at which time LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," MODE 4 requirements, may be changed to allow the single control rod withdrawn to be assumed to be the highest worth control rod.

APPLICABILITY: MODE 4 with the reactor mode switch in the refuel position.

BASES

APPLICABLE SAFETY ANALYSES (continued)

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed in compliance with the prescribed sequences of LCO 3.1.6, and during these tests, no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended, provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence are satisfied. Assurances that the test sequence is followed can be provided by either programming the test sequence into the RWM, with conformance verified as specified in SR 3.3.2.1.8 and allowing the RWM to monitor control rod withdrawal and provide appropriate control rod blocks if necessary, or by verifying conformance to the approved test sequence by a second licensed operator (Reactor Operator or Senior Reactor Operator) or other task qualified member of the technical staff (e.g., shift technical advisor or reactor engineer). These controls are consistent with those normally applied to operation in the startup range as defined in the SRs and ACTIONS of LCO 3.3.2.1, "Control Rod Block Instrumentation."

APPLICABILITY

Control rod testing, while in MODES 1 and 2, with THERMAL POWER greater than 10% RTP, is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," and LCO 3.3.2.1. With THERMAL POWER less than or equal to 10% RTP, the provisions of this

(continued)

BASES

APPLICABILITY (continued)

Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed sequences of LCO 3.1.6.

While in MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.2, "Single Control Rod Withdrawal—Hot Shutdown," or Special Operations LCO 3.10.3, "Single Control Rod Withdrawal—Cold Shutdown," which provide adequate controls to ensure that the assumptions of the safety analysis of References 1, 2, 3, 4, and 5 are satisfied. During these Special Operations and while in MODE 5, the one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock,") and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling"), or the added administrative controls prescribed in the applicable Special Operations LCOs, provide mitigation of potential reactivity excursions.

ACTIONS

A.1

With the requirements of the LCO not met (e.g., the control rod pattern is not in compliance with the special test sequence, the sequence is improperly loaded in the RWM) the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer excepted, and appropriate actions are to be taken to restore the control rod sequence to the prescribed sequence of LCO 3.1.6, or to shut down the reactor, if required by LCO 3.1.6.

SURVEILLANCE REQUIREMENTS

SR 3.10.6.1

With the special test sequence not programmed into the RWM, a second licensed operator (Reactor Operator or Senior Reactor Operator) or other task qualified member of the technical staff (e.g., shift technical advisor or reactor engineer) is required to verify conformance with the approved sequence for the test. This verification must be performed during control rod movement to prevent deviations from the specified sequence. A Note is added to indicate that this Surveillance does not need to be met if SR 3.10.6.2 is satisfied.

(continued)

<CTS>

[3]

3.10 SPECIAL OPERATIONS

3.10.3 Single Control Rod Withdrawal—Cold Shutdown

LCO 3.10.3

<LCO 3.10.I>
<Table 1-2 footnote b>
<Table 1-2 footnote e>
<LCO 3.10.A>

The reactor mode switch position specified in Table 1.1-1 for MODE 4 may be changed to include the refuel position, and operation considered not to be in MODE 2, to allow withdrawal of a single control rod, and subsequent removal of the associated control rod drive (CRD) if desired, provided the following requirements are met:

<LCO 3.10.I.4.a>
<LCO 3.10.I.5>

a. All other control rods are fully inserted;

<Table 1-2 footnote b>
<Table 1-2 footnote e>
<DOC M.1>

b. 1. LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," and

LCO 3.9.4, "Control Rod Position Indication,"

<u>OR</u>

<DOC L.2>

2. A control rod withdrawal block is inserted; and [D]

<DOC L.2>

c. 1. LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," MODE 5 requirements for Functions ~~1~~1.a, 1.b, 7.a, 7.b, ~~10, and 11~~ 11, and 12 of Table 3.3.1.1-1, ~~and~~ [1] [2]

LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," MODE 5 requirements, and

LCO 3.9.5, "Control Rod OPERABILITY—Refueling,"

<u>OR</u>

<LCO 3.10.I.3>
<LCO 3.10.I.4>
<LCO 3.10.I.4.a>

2. All other control rods in a five by five array centered on the control rod being withdrawn are disarmed; at which time LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," MODE 4 requirements, may be changed to allow the single control rod withdrawn to be assumed to be the highest worth control rod.

<LCO 3.10.I.1>
<Appl 3.10.I>
<Table 1-2 footnote b>
<Appl 3.10.A>
<LCO 3.10.A footnote a>

APPLICABILITY: MODE 4 with the reactor mode switch in the refuel position.

B 3.10 SPECIAL OPERATIONS

B 3.10.2 Reactor Mode Switch Interlock Testing

1 5

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit operation of the reactor mode switch from one position to another to confirm certain aspects of associated interlocks during periodic tests and calibrations in MODES 3, 4, and 5.

The reactor mode switch is a conveniently located, multiposition, keylock switch provided to select the necessary scram functions for various plant conditions (Ref. 1). The reactor mode switch selects the appropriate trip relays for scram functions and provides appropriate bypasses. The mode switch positions and related scram interlock functions are summarized as follows:

a. Shutdown—Initiates a reactor scram; bypasses main steam line isolation and reactor high water level scrams; 1

low turbine condenser vacuum

b. Refuel—Selects Neutron Monitoring System (NMS) scram function for low neutron flux level operation (but does not disable the average power range monitor scram); bypasses main steam line isolation and reactor high water level scrams; 1

c. Startup/Hot Standby—Selects NMS scram function for low neutron flux level operation (intermediate range monitors and average power range monitors); bypasses main steam line isolation and reactor high water level scrams; and 1

d. Run—Selects NMS scram function for power range operation.

The reactor mode switch also provides interlocks for such functions as control rod blocks, scram discharge volume trip bypass, refueling interlocks, suppression pool makeup, and main steam isolation valve isolations. 1

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

purpose 2

The ~~acceptance criterion~~ for reactor mode switch interlock testing is to prevent fuel failure by precluding reactivity excursions or core criticality. The interlock functions of the shutdown and refuel positions normally maintained for the reactor mode switch in MODES 3, 4, and 5 are provided to preclude reactivity excursions that could potentially result in fuel failure. Interlock testing that requires moving the reactor mode switch to other positions (run, startup/hot standby, or refuel) while in MODE 3, 4, or 5, requires administratively maintaining all control rods inserted and no ~~other~~ CORE ALTERATIONS in progress. With all control rods inserted in core cells containing one or more fuel assemblies, and no CORE ALTERATIONS in progress, there are no credible mechanisms for unacceptable reactivity excursions during the planned interlock testing. 3

For postulated accidents, such as control rod removal error during refueling ~~or loading of fuel with a control rod withdrawn~~, the accident analysis demonstrates that fuel failure will not occur (Ref~~s~~. 2 ~~and 3~~). The withdrawal of a single control rod will not result in criticality when adequate SDM is maintained. Also, loading fuel assemblies into the core with a single control rod withdrawn will not result in criticality, thereby preventing fuel failure. 1 Δ

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of ~~the NRC Policy Statement~~ 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases. 1

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. MODES 3, 4, and 5 operations not specified in Table 1.1-1 can be performed in accordance with other Special Operations LCOs (i.e., ~~LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation,"~~ 3 LCO 3.10.~~3~~ 2, "Single Control Rod Withdrawal—Hot Shutdown," LCO 3.10.~~4~~ 3, "Single Control Rod Withdrawal—Cold Shutdown," and LCO 3.10.~~8~~ 7, "SDM Test—Refueling") without meeting this LCO or its ACTIONS. If any testing is performed that involves the reactor mode switch interlocks and requires repositioning beyond that specified in Table 1.1-1 for the 5

(continued)

BASES

APPLICABILITY (continued)

While in MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.~~2~~ 2, "Single Control Rod Withdrawal—Hot Shutdown," or Special Operations LCO 3.10.~~3~~ 3, "Single Control Rod Withdrawal—Cold Shutdown," which provide adequate controls to ensure that the assumptions of the safety analys~~es~~ i of Reference~~s 1 and 2~~ 5 are satisfied. During these Special Operations and while in MODE 5, the one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock,") and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling"), or the added administrative controls prescribed in the applicable Special Operations LCOs, provide mitigation of potential reactiv~~e~~ ity excursions.

1 2 2 1, 2, 3, 4, and 5 2 6

ACTIONS

A.1

With the requirements of the LCO not met (e.g., the control rod pattern is not in compliance with the special test sequence, the sequence is improperly loaded in the RWM) the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer excepted, and appropriate actions are to be taken to restore the control rod sequence to the prescribed sequence of LCO 3.1.6, or to shut down the reactor, if required by LCO 3.1.6.

1 6

SURVEILLANCE REQUIREMENTS

SR 3.10.~~8~~ 6.1

With the special test sequence not programmed into the RWM, a second licensed operator (Reactor Operator or Senior Reactor Operator) or other task qualified member of the technical staff (e.g., shift Technical advisor or reactor engineer) is required to verify conformance with the approved sequence for the test. ~~[Note: A member of the technical staff is considered to be qualified if he possesses skills equal to a licensed operator [in the following areas:].]~~ This verification must be performed during control rod movement to prevent deviations from the specified sequence. A Note is added to indicate that this Surveillance does not need to be ~~performed~~ met if SR 3.10.~~8~~ 6.2 is satisfied.

3 3 5 7 1 6 3

(continued)

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The station manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

5.1.2 A unit supervisor shall be responsible for the control room command function (Since the control room is common to both units, the control room command function for both units can be satisfied by a single unit supervisor). During any absence of the unit supervisor from the control room while the unit is in MODE 1, 2, or 3, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the unit supervisor from the control room while the unit is in MODE 4 or 5 or defueled, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function. D

5.2 Organization

5.2.2 Unit Staff (continued)

a. A total of three non-licensed operators for the two units is required in all conditions. At least one of the required non-licensed operators shall be assigned to each unit.

b. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and Specifications 5.2.2.a and 5.2.2.f for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. A radiation protection technician shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

d. The amount of overtime worked by unit staff members performing safety related functions shall be limited and controlled in accordance with the NRC Policy Statement on working hours (Generic Letter 82-12).

e. The operations manager or shift operations supervisor shall hold an SRO license.

f. The Shift Technical Advisor (STA) shall provide advisory technical support to the shift manager in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. In addition, the STA shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

5.5 Programs and Manuals

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

a. The limits for concentrations of hydrogen in the Off-Gas 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 shall establish the required testing of both new fuel oil and stored fuel oil. 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: D

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, C

2. A flash point and kinematic viscosity within limits, and

3. A clear and bright appearance with proper color or water and sediment within limits; C

(continued)

ADMINISTRATIVE

A.1 In the conversion of the Quad Cities 1 and 2 current Technical Specifications (CTS) to the proposed plant specific Improved Technical Specifications (ITS), certain wording preferences or conventions are adopted that do not result in technical changes (either actual or interpretational). Editorial changes, reformatting, and revised numbering are adopted to make the ITS consistent with the BWR Standard Technical Specifications, NUREG 1433, Rev. 1 (i.e., the Improved Standard Technical Specifications (ISTS)).

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A new requirement has been added, ITS 5.1.2, which requires a unit supervisor to be responsible for the control room command function (except during his absence, and then a designated licensed individual). This requirement ensures that an individual is designated to be in command of the control room at all times. This change is a more restrictive change on plant operations. C D

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 CTS 6.1.A uses the title "Station Manager." In ITS 5.1.1, this specific title is replaced with the generic title "station manager." The specific title is proposed to be relocated to the Quality Assurance (QA) Manual, which is where the description of this specific title is currently located. The allowance to relocate the specific title out of the Technical Specifications is consistent with the NRC letter from C. Grimes to the Owners Groups Technical Specification Committee Chairmen, dated November 10, 1994. The various requirements of the station manager are still retained in the ITS. In addition, the ITS also requires the plant specific titles to be in the QA Manual. Therefore, the relocated specific title is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the QA Manual are controlled by the provisions of 10 CFR 50.54.

LA.2 CTS 6.1.B delineates the responsibility of the Shift Engineer for directing and commanding the overall operation of the facility on his shift. This requirement is relocated to the UFSAR. ITS 5.1.2 contains the requirement that a unit supervisor shall be responsible for the control room command function (except during his absence, and then a designated licensed individual). Since ITS 5.1.2 C D

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.2 (cont'd) provides requirements for the control room command function, as a result inclusion of the detailed responsibilities of the Shift Engineer in the ITS is not required to provide adequate protection of the public health and safety. Changes to the UFSAR are controlled by the provisions of 10 CFR 50.59.

"Specific"

None

RELOCATED SPECIFICATIONS

None

DISCUSSION OF CHANGES
ITS: 5.3 - UNIT STAFF QUALIFICATIONS

ADMINISTRATIVE

A.1 In the conversion of the Quad Cities 1 and 2 current Technical Specifications (CTS) to the proposed plant specific Improved Technical Specifications (ITS), certain wording preferences or conventions are adopted that do not result in technical changes (either actual or interpretational). Editorial changes, reformatting, and revised numbering are adopted to make the ITS consistent with the BWR Standard Technical Specifications, NUREG 1433, Rev. 1 (i.e., the Improved Standard Technical Specifications (ISTS)).

A.2 The details in CTS 6.3 for qualification requirements of the Shift Technical Advisor (STA) position are being deleted. These requirements are adequately addressed in CTS 6.2.C (proposed ITS 5.2.2.f) "specified by the Commission Policy Statement on Engineering Expertise on Shift," and therefore, it is unnecessary to restate the qualification requirements. Since the STA position requirements are retained in proposed ITS 5.2.2.f, this change is considered administrative.

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 CTS 6.3 uses the plant titles "Rad/Chem Superintendent," and "Lead Health Physicist." In ITS 5.3.1, these specific titles are replaced with the generic titles "radiation protection manager" and "lead radiation protection technician," respectively. The specific title is proposed to be relocated to the Quality Assurance (QA) Manual, which is where the description of these specific titles are currently located. The allowance to relocate the specific titles out of the Technical Specifications is consistent with the NRC letter from C. Grimes to the Owners Groups Technical Specification Committee Chairmen, dated November 10, 1994. In addition, the ITS also requires the plant specific titles to be in the QA Manual. Therefore, the relocated specific title is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the QA Manual are controlled by the provisions of 10 CFR 50.54.

<CTS>

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

station — 2 — manager — TSTF-65

Reviewer's Note not shown

<6.1.A> 5.1.1 The ~~{Plant Superintendent}~~ station manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence. TSTF-65 1

~~The {Plant Superintendent} manager or his designee shall approve, prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety.~~ 3

A unit supervisor — 2

<6.1.B><LA 2> 5.1.2 ~~The [Shift Supervisor (SS)]~~ A unit supervisor shall be responsible for the control room command function. ~~During any absence of the {SS} unit supervisor from the control room while the unit is in MODE 1, 2, or 3, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the {SS} unit supervisor from the control room while the unit is in MODE 4 or 5, or defueled, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.~~ D

2 unit supervisor

or defueled, 4

4 (Since the control room is common to both units, the control room command function for both units can be satisfied by a single unit supervisor) D

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1433, REVISION 1
ITS 5.1 - RESPONSIBILITY

1. This reviewer's note has been deleted. This information is for the NRC reviewer to be keyed in to what is needed to meet the TSTF-65 allowance. This is not meant to be retained in the final version of the plant specific submittal.

2. The brackets have been removed and the proper plant specific information has been provided.

3. The second paragraph of ISTS 5.1.1, regarding review and approval of tests or experiments is deleted. CTS do not delineate this requirement.

4. ISTS 5.1.2 is revised to reflect plant practice. D

<CTS>

5.2 Organization

5.2.2 Unit Staff (continued)

[5]

shall be assigned for each control room from which a reactor is operating in MODES 1, 2, or 3.

[Two unit sites with both units shutdown or defueled require a total of three non-licensed operators for the two units.]

TSTF-258

b. At least one licensed Reactor Operator (RO) shall be present in the control room when fuel is in the reactor. In addition, while the unit is in MODE 1, 2, or 3, at least one licensed Senior Reactor Operator (SRO) shall be present in the control room.

<6.2.B.3>

b ~~c~~. Shift crew composition may be less than ~~the minimum requirement of 10 CFR 50.54(m)(2)(i) and~~ 5.2.2.a and 5.2.2.~~g~~ f Specifications for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

[6] TSTF-258

<6.2.B.4> radiation protection TSTF-258 [1] TSTF-65

c ~~d~~. A ~~Health Physics~~ Technician ~~X~~ shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

<6.2.B.4>

[1]

d ~~e~~. [Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety related functions (e.g., licensed SROs, licensed ROs, health physicists, auxiliary operators, and key maintenance personnel).

Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work an [8 or 12] hour day, nominal 40 hour week while the unit is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance, or major plant modification, on a temporary basis the following guidelines shall be followed:

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time;]

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1433, REVISION 1
ITS: 5.2 - ORGANIZATION

1. The brackets have been removed and the proper plant specific information has been provided.

2. Typographical/grammatical error corrected.

3. Changes have been made (additions, deletions, and/or changes to the NUREG) to reflect the plant specific nomenclature, number, reference, system description, analysis description, or licensing basis description.

5. Editorial changes made for enhanced clarity.

6. Changes have been made to ISTS 5.2.2.a to be consistent with current licensing basis.

7. The referenced requirements are Specifications, not CFR requirements. Therefore, the word "Specifications" has been added to clearly state that "5.2.2.a and 5.2.2.f" are Specifications. D

8. The proper plant specific description of the individual to whom the STA provides technical support has been provided.

9. ISTS 5.2 (Organization) is revised by TSTF-258, Rev. 4. In order to maintain consistency, to the maximum extent practicable, between the Administrative Controls Technical Specifications of the ComEd nuclear stations, the following changes of TSTF-258, Rev. 4, are not incorporated in ITS 5.2: C

   a. ISTS 5.2.2.e contains requirements for control of overtime of the plant staff. These requirements were revised by TSTF-258, Rev. 4. C

   b. ISTS 5.2.2.g contains requirements for the Shift Technical Advisor. The title "Shift Technical Advisor (STA)" was deleted by TSTF-258, Rev. 4. C

   Not incorporating these changes to ISTS 5.2 is consistent with the NRC approved ITS for the ComEd Byron and Braidwood Stations.

5.5 Programs and Manuals (continued)

5.5.~~10~~ 9 [9] Diesel Fuel Oil Testing Program (shall establish the) [11]

<4.9.A.5.a> 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: [10]

<4.9.A.5.a> <4.9.A.5.b> a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

1. ~~a~~n API gravity or an absolute specific gravity within limits, [1]

2. ~~a~~ flash point and kinematic viscosity within limits ~~for ASTM 2D fuel oil~~, and [17] (or water and sediment within limits)

3. ~~a~~ clear and bright appearance with proper color;

<4.9.A.5.c> <4.9.A.6.a> [16] (Insert 5.5.9.b) b. ~~Other properties for ASTM 2D fuel oil are within limits~~ ~~w~~ithin 31 days following ~~sampling and~~ addition (of the new fuel oil) to storage tanks; and [TSTF-106]

c. Total particulate concentration of the fuel oil ([18] in the storage tanks) is ≤ 10 mg/l when tested every 31 days in accordance with (applicable) ASTM ~~D-2276~~, (Standard) ~~Method A-2 or A-3~~. [TSTF-118]

[17] (The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program test frequencies.)

5.5.~~11~~ 10 [9] Technical Specifications (TS) Bases Control Program

<DOC M.2> 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 ~~involve~~ (require) either of the following: [TSTF-364]

[1]

1. ~~a~~ change in the TS incorporated in the license; or

2. ~~a~~ change to the updated (U) FSAR or Bases that ~~involves an unreviewed safety question as defined in~~ (requires NRC approval pursuant to) 10 CFR 50.59. [8] [TSTF-364]

(continued)

TSTF-152

INSERT 5.6.1

1 2 3

A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors), for whom monitoring was performed, receiving an annual deep dose equivalent > 100 mrem and the associated man collective deep dose equivalent (reported in ~~person~~-rem) according to work and job functions (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling). This tabulation supplements the requirements of 10 CFR 20.2206. The dose assignments to various duty functions may be estimated based on pocket ionization chamber, thermoluminescence dosimeter (TLD), or ~~electronic dosimeter, or film badge~~ measurements. Small exposures totaling < 20 ~~percent~~ % of the individual total dose need not be accounted for. In the aggregate, at least 80 ~~percent~~ % of the total deep dose equivalent received from external sources should be assigned to specific major work functions. The report covering the previous calendar year shall be submitted by April 30 of each year. ~~[The initial report shall be submitted by April 30 of the year following initial criticality.]~~ 1 D 1 D all changes are 1 unless otherwise identified

TSTF-258 changes not adopted

<CTS>

5.0 ADMINISTRATIVE CONTROLS

<6.12>

[5.7 High Radiation Area]

at 30cm (12 in.)

radiation protection technicians

<6.12.A> 5.7.1 Pursuant to 10 CFR 20, paragraph 20.1601(c), in lieu of the requirements of 10 CFR 20.1601, each high radiation area, as defined in 10 CFR 20, in which the intensity of radiation is > 100 mrem/hr ~~but < 1000 mrem/hr~~, shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP) (or equivalent document). Individuals ~~qualified in radiation protection procedures (e.g., [Health Physics Technicians])~~ or personnel ~~continuously~~ escorted by such individuals may be exempt from the RWP issuance requirement during the performance of their assigned duties ~~in high radiation areas with exposure rates ≤ 1000 mrem/hr~~, provided they are otherwise following plant radiation protection procedures for entry into ~~such~~ high radiation areas. 1 D

Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

<6.12.A.1> a. A radiation monitoring device that continuously indicates the radiation dose rate in the area.

<6.12.A.2> b. A radiation monitoring device that continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel are aware of them.

<6.12.A.3> c. An individual qualified in radiation protection procedures with a radiation dose rate monitoring device, who is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified ~~by the [Radiation Protection Manager]~~ in the RWP (or equivalent document). 1 D

accessible to personnel

<6.12.B> 5.7.2 In addition to the requirements of Specification 5.7.1, areas with radiation levels > 1000 mrem/hr ~~shall be provided with locked or continuously guarded doors to prevent unauthorized entry and the keys shall be maintained under the administrative control of the Shift Foreman on duty or health physics supervision. Doors shall remain locked except during periods of access by personnel under an approved RWP that shall specify the dose rate levels in the immediate work~~

Insert 5.7.2

(continued)

ATTACHMENT 4

Additional Comment on Draft Safety Evaluation

TABLE LA - REMOVAL OF DETAILS MATRIX AND SPECIFICATION REQUIREMENTS
SECTION 3.9 - REFUELING OPERATIONS

ITS SECTION AND DOC #	CTS SECTION	SUMMARY	LOCATION	CHANGE CONTROL PROCESS	CHANGE TYPE
Current Specification 3/4.9.4, Decay Time					
NONE	NONE	NONE	NONE	NONE	NONE
Current Specification 3/4.9.5, Communications					
NONE	NONE	NONE	NONE	NONE	NONE
Current Specification 3/4.9.6, Crane and Hoist					
NONE	NONE	NONE	NONE	NONE	NONE
Current Specification 3/4.9.7, Crane Travel					
None - LA.1 ~~NONE~~	~~NONE~~	~~NONE~~ Crane travel requirements.	UFSAR ~~NONE~~	10 CFR 50.59 ~~NONE~~	3 ~~NONE~~
	3/4.9.7				

TABLE R - RELOCATED SPECIFICATIONS
SECTION 3.9 - REFUELING OPERATIONS

ITS SECTION AND DOC #	CTS SECTION	SUMMARY	LOCATION	CHANGE CONTROL PROCESS
Current Specification 3/4.9.7, Crane Travel				
NONE ~~None R.1~~	~~3/4. 3/4.9.6~~ NONE	~~Crane travel requirements.~~ NONE	NONE ~~TRM~~	NONE ~~10 CFR 50.59~~