1.1 Definitions

DOSE EQUIVALENT I-131 (continued)	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."
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.
END OF CYCLE RECIRCULATION PUMP TRIP (EOC-RPT) SYSTEM RESPONSE TIME	The EOC-RPT SYSTEM RESPONSE TIME shall be that time interval from initial movement of the associated turbine stop valves or turbine control valves 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. B
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. 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.
LEAKAGE	LEAKAGE shall be: a. <u>Identified LEAKAGE</u> 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

(continued)

A.1

DEFINITIONS

EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME

A.1 1.12 (Continued)

means of A.1

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 any series of sequential, overlapping, or total steps so that the entire response time is measured. A.1

END-OF-CYCLE RECIRCULATION PUMP TRIP (EOC-RPT) SYSTEM RESPONSE TIME

1.13 The END-OF-CYCLE RECIRCULATION PUMP TRIP (EOC-RPT) SYSTEM RESPONSE TIME shall be that time interval to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker from initial movement of the associated A.1

a. Turbine stop valves, or
b. Turbine control valves

means of A.1

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

FRACTION OF LIMITING POWER DENSITY A.6

1.14 The FRACTION OF LIMITING POWER DENSITY (FLPD) shall be the LINEAR HEAT GENERATION RATE (LHGR) existing at a given location divided by the specified LHGR limit for that bundle type.

INSERT INTO CMFLPD Definition Page 1-2a

FRACTION OF RATED THERMAL POWER

1.15 The FRACTION OF RATED THERMAL POWER (FRTP) shall be the measured THERMAL POWER divided by the RATED THERMAL POWER. LA.1

FREQUENCY NOTATION

1.16 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1. A.8

GASEOUS RADWASTE TREATMENT SYSTEM

1.17 A GASEOUS RADWASTE TREATMENT SYSTEM shall be any system designed and installed to reduce radioactive gaseous effluents by collecting offgases from the main condenser evacuation system and providing for delay or holdup for the purpose of reducing the total radioactivity prior to release to the environment. A.2

A.9 IDENTIFIED LEAKAGE

1.18 IDENTIFIED LEAKAGE shall be: A.10 the drywell that from A.1

1.a. Leakage into collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank; or A.1 A.1 A.1 A.1

a. Identified LEAKAGE A.9

1.1 Definitions

1.10 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."

1.12 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.

1.13 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].

movement of the associated turbine stop valves or turbine control valves

1.19 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

(continued)

Chapter 2.0

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires, and SLs ensure, that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs).

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a stepback approach is used to establish an SL, such that the MCPR is not less than the limit specified in Specification 2.1.1.2. MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. (B)

The fuel cladding is one of the physical barriers that separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses, which occur from reactor operation significantly above design conditions.

While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross, rather than incremental, cladding deterioration. Therefore, the fuel cladding SL is defined with a margin to the conditions that would produce onset of transition boiling (i.e., MCPR = 1.00). These conditions represent a significant departure from the condition intended by design for planned operation. The MCPR fuel cladding integrity SL ensures that during normal operation and during AOOs, at least 99.9% of the fuel rods in the core do not experience transition boiling.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of transition boiling and the resultant sharp

(continued)

BASES

APPLICABLE SAFETY ANALYSES

2.1.1.1 Fuel Cladding Integrity (continued)

data taken at pressures from 14.7 psia to 800 psia 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.

2.1.1.2 MCPR

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Since the parameters that result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions that result in the onset of transition boiling have been used to mark the beginning of the region in which fuel damage could occur. Although it is recognized that the onset of transition boiling would not result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. However, the uncertainties in monitoring the core operating state and in the procedures used to calculate the critical power result in an uncertainty in the value of the critical power. Therefore, the fuel cladding integrity SL is defined as the critical power ratio in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition, considering the power distribution within the core and all uncertainties.

The MCPR SL is determined using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved General Electric Critical Power correlations. Details of the fuel cladding integrity SL calculation are given in References 3 and 4. Reference 3 also includes a tabulation of the uncertainties used in the determination of the MCPR SL and Reference 4 also provides the nominal values of the parameters used in the MCPR SL statistical analysis.

(continued)

BASES

SAFETY LIMIT VIOLATIONS

2.2 (continued)

rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and also assures that the probability of an accident occurring during this period is minimal.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 14 and GDC 15. B

2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.

3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWA-5000.

4. 10 CFR 100.

5. ASME, Boiler and Pressure Vessel Code, Section III, 1971 Edition, Addenda, winter of 1972.

6. ASME, Boiler and Pressure Vessel Code, Section III, 1977 Edition, Addenda, summer of 1977.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires, and SLs ensure, that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs).

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a stepback approach is used to establish an SL, such that the MCPR is not less than the limit specified in Specification 2.1.1.2 for [both General Electric Company (GE) and Advanced Nuclear Fuel Corporation (ANF) fuel]. MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity.

The fuel cladding is one of the physical barriers that separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses, which occur from reactor operation significantly above design conditions.

While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross, rather than incremental, cladding deterioration. Therefore, the fuel cladding SL is defined with a margin to the conditions that would produce onset of transition boiling (i.e., MCPR = 1.00). These conditions represent a significant departure from the condition intended by design for planned operation. The MCPR fuel cladding integrity SL ensures that during normal operation and during AOOs, at least 99.9% of the fuel rods in the core do not experience transition boiling.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

2.1.1.2a MCPR [GE/Fuel]

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Since the parameters that result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions that result in the onset of transition boiling have been used to mark the beginning of the region in which fuel damage could occur. Although it is recognized that the onset of transition boiling would not result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. However, the uncertainties in monitoring the core operating state and in the procedures used to calculate the critical power result in an uncertainty in the value of the critical power. Therefore, the fuel cladding integrity SL is defined as the critical power ratio in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition, considering the power distribution within the core and all uncertainties.

The MCPR SL is determined using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved General Electric Critical Power correlations. Details of the fuel cladding integrity SL calculation are given in References 3 and 4. Reference 3 also includes a tabulation of the uncertainties used in the determination of the MCPR SL and the nominal values of the parameters used in the MCPR SL statistical analysis. Reference 4 also provides

2.1.1.2b MCPR [ANF Fuel]

The MCPR SL ensures sufficient conservatism in the operating MCPR limit that, in the event of an AOO from the limiting condition of operation, at least 99.9% of the fuel rods in the core would be expected to avoid boiling transition. The margin between calculated boiling transition (i.e., MCPR = 1.00) and the MCPR SL is based on a detailed statistical procedure that considers the uncertainties in monitoring the core operating state. One specific uncertainty included in the SL is the uncertainty inherent

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 14, GDC 15, and ~~GDC 28~~. 6

2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.

3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IW-5000. A 6

4. 10 CFR 100.

5. ASME, Boiler and Pressure Vessel Code, Section III, 1971 Edition, Addenda, winter of 1972.

6. ASME, Boiler and Pressure Vessel Code, 1971 Edition, Addenda, summer of 1977. 7

7. 10 CFR 50.72.

8. 10 CFR 50.73.

2

TSTF-05

B

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: CHAPTER 2.0 - SAFETY LIMITS

1. Not used.

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

3. A description of the reactor vessel water level SL has been added, consistent with the background description of the other SLs.

4. NMP2 does not use ANF fuel. As a result, the Bases discussions for ANF fuel Safety Limits have been deleted and the requirements have been renumbered to reflect this change.

5. Editorial change made for clarity.

6. Typographical/grammatical error corrected.

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

Section 3.0

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications in Sections 3.1 through 3.10 and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a Special Operations LCO are only applicable when the Special Operations LCO is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. B

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

(continued)

Section 3.0

A.1

3.0 SURVEILLANCE REQUIREMENTS (SR) APPLICABILITY

SR 3.0.1 4.0.1 Surveillance Requirements (SRs) shall be met during the OPERATIONAL CONDITIONS (MODES) or other conditions specified (in the Applicability) for individual Limiting Conditions for Operation (LCOs) unless otherwise stated (in the SRs) in an individual Surveillance Requirement. (INSERT 8) A.9 A.2

SR 3.0.2 4.0.2 Each Surveillance Requirement shall be performed within the specified time interval with a maximum allowable extension not to exceed 25% of the surveillance interval. Insert 9 See Insert 8 for discussion of changes comment numbers

SR 3.0.3 4.0.3 Failure to perform a Surveillance Requirement within the allowed surveillance interval, defined by Specification 4.0.2, shall constitute noncompliance with the OPERABILITY requirements for a Limiting Condition for Operation. The time limits of the ACTION requirements are applicable at the time it is identified that a Surveillance Requirement has not been performed. The ACTION requirements may be delayed for up to 24 hours to permit the completion of the surveillance when the allowable outage time limits of the ACTION requirements are less than 24 hours. Surveillance Requirements do not have to be performed on inoperable equipment. A.9 moved to SR 3.0.1 Insert 10 L.4 A.2

SR 3.0.4 4.0.4 Entry into an OPERATIONAL CONDITION or other specified applicable condition shall not be made unless the Surveillance Requirement(s) associated with the Limiting Condition for Operation have been performed within the applicable surveillance interval or as otherwise specified. This provision shall not prevent passage through or to OPERATIONAL CONDITIONS as required to comply with ACTION requirements. A.9 moved to SR 3.0.1 Insert 11 A.11

4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2, and 3 components shall be applicable as follows:

a. Inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10CFR50.55a(f), except where specific written relief has been granted by the Commission pursuant to 10CFR50.55a(f)(6)(i). Inservice inspection of ASME Code Class 1, 2, and 3 components shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i). B

b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda for the inservice inspection and testing activities required by the ASME Boiler and Pressure Vessel Code and applicable addenda shall be applicable as follows in these Technical Specifications:

A.12 moved to Specification 5.5.6

B 3.0. SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated. in Sections 3.1 through 3.10 1

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a Special Operations LCO are only applicable when the Special Operations LCO is used as an allowable exception to the requirements of a Specification.

11 TSTF-8

Insert SR 3.0.1

B

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

(continued)

TSTF-8

INSERT SR 3.0.1

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given MODE or other specified condition.

B

11

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: SECTION 3.0 - LCO AND SR APPLICABILITY

1. The LCO and SR Applicability only apply to Specifications in Sections 3.1 through 3.10; they do not apply to Specifications in Chapters 4.0 and 5.0. Therefore, this statement has been added for clarity.

2. Typographical/grammatical error corrected.

3. The correct LCO number or plant specific nomenclature, as appropriate, has been provided.

4. The correct LCO title and fuel pool description has been provided. The NMP2 Spent Fuel Storage Pool design is similar to that described in the BWR/4 Improved Technical Specifications, NUREG-1433, Revision 1; thus the words have been changed to be consistent with the wording in NUREG-1433, Revision 1.

5. The paragraph has been moved, consistent with change package BWR-26, C.1. This change was inadvertently left out when NUREG-1434, Revision 1 was promulgated.

6. The bracketed "Reviewer's Note" has been deleted. This information is for the NRC reviewer to be keyed in to what is needed to meet this requirement. This is not meant to be retained in the final version of the plant specific submittal.

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

8. These words have been added for clarity. Failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction only if the equipment is already inoperable.

9. The original wording of the Bases of LCO 3.0.2 is confusing in that it begins to discuss inoperability of redundant equipment without introducing this topic. This topic of inoperable redundant equipment seems to be more appropriate for the Bases of LCO 3.0.3, but an appropriate discussion is already provided there. The proposed wording retains the intent while presenting the material in the appropriate context of LCO 3.0.2. This change is also being proposed in TSTF-122.

10. Changes have been made to reflect these changes made to the Specifications in Section 3.6.

11. TSTF-8 adds a clarification to the Bases of SR 3.0.1 that allows credit to be taken for unplanned events that satisfy Surveillances. This clarification also states that this allowance also includes those SRs whose performance is precluded in a given MODE or other specified condition. This portion of the TSTF has not been adopted. As documented in the Part 9900 of the NRC Inspection Manual, Technical Guidance - Licensee Technical Specifications Interpretations, and in the ITS Bases Control

B

11. (continued)

Program (ITS 5.5.10), neither the Technical Specification Bases nor Licensee generated interpretations can be used to change the Technical Specification requirements. Thus, if the Technical Specifications preclude performance of an SR in certain MODES (as is the case for some SRs in ITS Section 3.8), the Bases cannot change the Technical Specifications requirement and allow the SR to be credited for being performed in the restricted MODES, even if the performance is unplanned. Therefore, only the first part of the TSTF-8 change to SR 3.0.1 has been adopted. B

Volume 2
Sections 3.1 and 3.2

Section 3.1

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.7

Demonstrating each SLC System pump develops a flow rate ≥ 41.2 gpm at a discharge pressure ≥ 1235 psig ensures that pump performance has not degraded during the fuel cycle. This minimum pump flow rate requirement ensures that, when combined with the sodium pentaborate solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the positive reactivity effects encountered during power reduction, cooldown of the moderator, and xenon decay. This test confirms one point on the pump design curve, and is indicative of overall performance. Such inservice tests confirm component OPERABILITY and detect incipient failures by indicating abnormal performance. The Frequency of this Surveillance is in accordance with the Inservice Testing Program.

SR 3.1.7.8 and SR 3.1.7.9

These Surveillances ensure that there is a functioning flow path from the boron solution storage tank to the RPV, including the firing of an explosive valve. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of that batch successfully fired. The pump and explosive valve tested should be alternated such that both complete flow paths are tested every 48 months, at alternating 24 month intervals. The Surveillance may be performed in separate steps to prevent injecting boron into the RPV. An acceptable method for verifying flow from the pump to the RPV is to pump demineralized water from a test tank through one SLC subsystem and into the RPV. While these Surveillances can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillances when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. B

Demonstrating that all heat traced piping between the boron solution storage tank and the suction valve to the injection pumps is unblocked ensures that there is a functioning flow

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.7 (continued)

Inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this Surveillance is in accordance with the Inservice Testing Program or 92 days.

SR 3.1.7.8 and SR 3.1.7.9

These Surveillances ensure that there is a functioning flow path from the boron solution storage tank to the RPV, including the firing of an explosive valve. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of that batch successfully fired. The pump and explosive valve tested should be alternated such that both complete flow paths are tested every 48 months, at alternating 24 month intervals. The Surveillance may be performed in separate steps to prevent injecting boron into the RPV. An acceptable method for verifying flow from the pump to the RPV is to pump demineralized water from a test tank through one SLC subsystem and into the RPV. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

Demonstrating that all heat traced piping between the boron solution storage tank and the suction inlet to the injection pumps is unblocked ensures that there is a functioning flow path for injecting the sodium pentaborate solution. An acceptable method for verifying that the suction piping is unblocked is to pump from the storage tank to the test tank. The 24 month Frequency is acceptable since there is a low probability that the subject piping will be blocked due to precipitation of the boron from solution in the heat traced piping. This is especially true in light of the daily temperature verification of this piping required by SR 3.1.7.3. However, if, in performing SR 3.1.7.3, it is

(continued)

Upon completion of this verification, the pump suction piping between the pump suction valve and pump suction must be drained and flushed with demineralized water, since this piping is not heat traced.

Section 3.2

3.2 POWER DISTRIBUTION LIMITS

3.2.4 Average Power Range Monitor (APRM) Gain and Setpoint

LCO 3.2.4

a. MFLPD shall be less than or equal to Fraction of RTP (FRTP); or

b. Each required APRM Flow Biased Simulated Thermal Power—Upscale Function Allowable Value shall be modified by ≤ FRTP/MFLPD; or

c. Each required APRM gain shall be adjusted such that the APRM readings are ≥ 100% times MFLPD.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	6 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.4.1	----------NOTE---------- Not required to be met if SR 3.2.4.2 is satisfied for LCO 3.2.4.b or LCO 3.2.4.c requirements. ---------- Verify MFLPD is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter
SR 3.2.4.2	----------NOTE---------- Not required to be met if SR 3.2.4.1 is satisfied for LCO 3.2.4.a requirements. ---------- Verify each required: a. APRM Flow Biased Simulated Thermal Power—Upscale Function Allowable Value is modified by ≤ FRTP/MFLPD; or b. APRM gain is adjusted such that the APRM reading is ≥ 100% times MFLPD.	12 hours

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.2.2

Because the transient analysis takes credit for conservatism in the scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analysis. SR 3.2.2.2 determines the value of τ, which is a measure of the actual scram speed distribution compared with the assumed distribution. The MCPR operating limit is then determined based on an interpolation between the applicable limits for Option A (scram times of LCO 3.1.4, "Control Rod Scram Times") and Option B (realistic scram times) analyses. The parameter τ must be determined once within 72 hours after each set of scram time tests required by SR 3.1.4.1, SR 3.1.4.2, and SR 3.1.4.4 because the effective scram speed distribution may change during the cycle or after maintenance that could affect scram times. The 72 hour Completion Time is acceptable due to the relatively minor changes in τ expected during the fuel cycle. B

REFERENCES

1. NUREG-0562, June 1979.

2. NEDE-24011-P-A, "GE Standard Application for Reactor Fuel," (revision specified in the COLR).

3. Supplemental Reload Licensing Report for Nine Mile Point Nuclear Station Unit 2, (revision specified in the COLR).

4. 10 CFR 50.36(c)(2)(ii).

5. "BWR/6 Generic Rod Withdrawal Error Analysis," General Electric Standard Safety Analysis Report, GESSAR-II, Appendix 15B.

BASES

LCO (continued)

Function Allowable Value by the ratio of FRTP to the core limiting value of MFLPD; or

c. Increasing the APRM gains to cause the APRM to read greater than 100(%) times MFLPD. This Condition is to account for the reduction in margin to the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit.

MFLPD is the ratio of the limiting LHGR to the LHGR limit for the specific bundle type. As power is reduced, if the design power distribution is maintained, MFLPD is reduced in proportion to the reduction in power. However, if power peaking increases above the design value, the MFLPD is not reduced in proportion to the reduction in power. Under these conditions, the APRM gain is adjusted upward or the APRM Flow Biased Simulated Thermal Power—Upscale Function Allowable Value is reduced accordingly. When the reactor is operating with peaking less than the design value, it is not necessary to modify the APRM Flow Biased Simulated Thermal Power—Upscale Function Allowable Value. Adjusting the APRM gain or modifying the APRM Flow Biased Simulated Thermal Power—Upscale Function Allowable Value is equivalent to maintaining MFLPD less than or equal to FRTP, as stated in the LCO.

For compliance with LCO Item b (APRM Flow Biased Simulated Thermal Power—Upscale Function Allowable Value modification) or Item c (APRM gain adjustment), only APRMs required to be OPERABLE per LCO 3.3.1.1, Function 2.b, are required to be modified or adjusted. In addition, each APRM may be allowed to have its gain adjusted or Allowable Value modified independently of other APRMs that are having their gain adjusted or Allowable Value modified.

APPLICABILITY

The MFLPD limit, APRM gain adjustment, or APRM Flow Biased Simulated Thermal Power—Upscale Function Allowable Value modification is provided to ensure that the fuel cladding integrity SL and the fuel cladding 1% plastic strain limit are not violated during design basis transients. As discussed in the Bases for LCO 3.2.1, LCO 3.2.2, and LCO 3.2.3, sufficient margin to these limits exists below 25% RTP and, therefore, these requirements are only necessary when the plant is operating at ≥ 25% RTP.

(continued)

A.1

Specification 3.2.4

POWER DISTRIBUTION LIMITS

3/4.2.2 AVERAGE POWER RANGE MONITOR SETPOINTS

LIMITING CONDITIONS FOR OPERATION

A.2

Allowable Value

modified by S FRTP/MFLPD

LCO 3.2.4.a 3.2.4.b

3.2.2 The Average Power Range Monitor (APRM) flow-biased simulated thermal power-upscale scram trip setpoint (S) shall be established according to the relationship specified in the CORE OPERATING LIMITS REPORT. A.4

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER. A.3

ACTION: LA.1

ACTION A

With the APRM flow-biased simulated thermal power-upscale scram trip setpoint less conservative than the value shown in the Allowable Value column for S, as above determined, initiate corrective action within 15 minutes and adjust S to be consistent with the Trip Setpoint value within 6 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

ACTION B

Allowable Value A.2

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

4.2.2 The FRACTION OF RATED THERMAL POWER (FRTP) and the CORE MAXIMUM FRACTION OF LIMITING POWER DENSITY (CMFLPD) shall be determined, the value of T•• calculated, and the most recent actual APRM flow-biased simulated thermal power-upscale scram trip setpoint verified to be within the above limit or adjusted, as required:

a. At least once per 24 hours,

≥25% L.1

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

SR 3.2.4.2

c. Initially and at least once per 12 hours when the reactor is operating with CMFLPD greater than or equal to FRTP.

d. The provisions of Specification 4.0.4 are not applicable. L.1

LCO 3.2.4.c

• With CMFLPD greater than the FRTP rather than adjusting the APRM setpoints, the APRM gain may be adjusted so that APRM readings are greater than or equal to 100% times CMFLPD provided that the adjusted APRM reading does not exceed 100% of RATED THERMAL POWER and a notice of adjustment is posted on the reactor control panel. L.2

•• Definition of T is specified in the CORE OPERATING LIMITS REPORT. A.4

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<CTS>

3.2 POWER DISTRIBUTION LIMITS

3.2.4 Average Power Range Monitor (APRM) Gain and Setpoints (Optional)

LCO 3.2.4

a. MFLPD shall be less than or equal to Fraction of RTP (FRTP); or

<LCO 3.2.2> <3.2.2 "*" Footnote>

b. Each required APRM setpoint specified in the COLR shall be made applicable; or

c. Each required APRM gain shall be adjusted such that the APRM readings are ≥ 100% times MFLPD.

<Appl. 3.2.2>

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

ACTIONS

<3.2.2 Act>

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	6 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

<3.2.2 Act>

Flow Biased Simulated Thermal Power - Upscale Function Allowable Value Shall be modified by ≤ FRTP/MFLPD;

<CTS>

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.4.1 <4.2.2> <4.2.2.a> <4.2.2.b>	----------NOTE---------- Not required to be met if SR 3.2.4.2 is satisfied for LCO 3.2.4.1 a, b or c requirements. ---------- LCO 3.2.4.	
	Verify MFLPD is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter
SR 3.2.4.2 <4.2.2.c>	----------NOTE---------- Not required to be met if SR 3.2.4.1 is satisfied for LCO 3.2.4.1 a requirements. ----------	
	Verify APRM setpoints or gains are adjusted for the calculated MFLPD.	12 hours

each required:

a. APRM Flow Biased Simulated Thermal Power-Upscale Function Allowable Value is modified by ≤ FRTP/MFLPD; or

b. APRM gain is adjusted such that the APRM reading is ≥ 100% times MFLPD.

3 INSERT 3.2.2.2

SR 3.2.2.2

Because the transient analysis takes credit for conservatism in the scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analysis. SR 3.2.2.2 determines the value of τ, which is a measure of the actual scram speed distribution compared with the assumed distribution. The MCPR operating limit is then determined based on an interpolation between the applicable limits for Option A (scram times of LCO 3.1.4, "Control Rod Scram Times") and Option B (realistic scram times) analyses. The parameter τ must be determined once within 72 hours after each set of scram time tests required by SR 3.1.4.1, SR 3.1.4.2, and SR 3.1.4.4 because the effective scram speed distribution may change during the cycle or after maintenance that could affect scram times. The 72 hour Completion Time is acceptable due to the relatively minor changes in τ expected during the fuel cycle. 1 B

1 INSERT REFERENCE

2. NEDE-24011-P-A, "GE Standard Application for Reactor Fuel," (revision specified in the COLR).

3. Supplemental Reload Licensing Report for Nine Mile Point Nuclear Station Unit 2, (revision specified in the COLR).

BASES

APPLICABLE SAFETY ANALYSES (continued)

to the operating limits (APLHGR, and MCPR, and LHGR) occurs. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and LCO 3.2.3, "Linear Heat Generation Rate (LHGR)," limit the initial margins to these operating limits at rated conditions so that specified acceptable fuel design limits are met during transients initiated from rated conditions. At initial power levels less than rated levels, the margin degradation of either the APLHGR, or the MCPR, or the LHGR during a transient can be greater than at the rated condition event. This greater margin degradation during the transient is primarily offset by the larger initial margin to limits at the lower than rated power levels. However, power distributions can be hypothesized that would result in reduced margins to the pretransient operating limit. When combined with the increased severity of certain transients at other than rated conditions, the SLs could be approached. At substantially reduced power levels, highly peaked power distributions could be obtained that could reduce thermal margins to the minimum levels required for transient events. To prevent or mitigate such situations, either the APRM gain is adjusted upward by the ratio of the core limiting MFLPD to the FRTP, or the flow biased APRM scram level is required to be reduced by the ratio of FRTP to the core limiting MFLPD. Either of these adjustments effectively counters the increased severity of some events at other than rated conditions by proportionally increasing the APRM gain or proportionally lowering the flow biased APRM scram setpoints dependent on the increased peaking that may be encountered.

Flow Biased Simulated Thermal Power-Upscale Function Allowable Value

The APRM gain and setpoints satisfy Criteria 2 and 3 of the NRC Policy Statement. Reference 4.

LCO

Meeting any one of the following conditions ensures acceptable operating margins for events described above:

a. Limiting excess power peaking;

b. Reducing the APRM flow biased neutron flux upscale scram setpoints by multiplying the APRM setpoints by the ratio of FRTP and the core limiting value of MFLPD; or

(continued)

Volume 3
Section 3.3; ITS, Bases, and CTS Markup/DOCs

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.1 and SR 3.3.1.2.3 (continued)

including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

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

SR 3.3.1.2.2

To provide adequate coverage of potential reactivity changes in the core when the fueled region encompasses more than one SRM, one SRM is required to be OPERABLE in the quadrant where CORE ALTERATIONS are being performed, and the other OPERABLE SRM must be in an adjacent quadrant containing fuel. Note 1 states that this SR is required to be met only during CORE ALTERATIONS. It is not required to be met at other times in MODE 5 since core reactivity changes are not occurring. This Surveillance consists of a review of plant logs to ensure that SRMs required to be OPERABLE for given CORE ALTERATIONS are, in fact, OPERABLE. In the event that only one SRM is required to be OPERABLE (when the fueled region encompasses only one SRM), per Table 3.3.1.2-1, footnote (b), only the a. portion of this SR is required. Note 2 clarifies that more than one of the three requirements can be met by the same OPERABLE SRM. The 12 hour Frequency is based upon operating experience and supplements operational controls over refueling activities, which include steps to ensure that the SRMs required by the LCO are in the proper quadrant.

SR 3.3.1.2.4

This Surveillance consists of a verification of the SRM instrument readout to ensure that the SRM reading is greater than a specified minimum count rate. This ensures that the detectors are indicating count rates indicative of neutron flux levels within the core. With few fuel assemblies 1B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.4 (continued)

loaded, the SRMs will not have a high enough count rate to satisfy the SR. Therefore, allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the minimum count rate.

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

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

SR 3.3.1.2.5 and SR 3.3.1.2.6

Performance of a CHANNEL FUNCTIONAL TEST demonstrates the associated channel will function properly. SR 3.3.1.2.5 is required in MODE 5, and the 7 day Frequency ensures that the channels are OPERABLE while core reactivity changes could be in progress. This 7 day Frequency is reasonable, based on operating experience and on other Surveillances (such as a CHANNEL CHECK) that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.d. RCIC Turbine Exhaust Diaphragm Pressure—High (continued)

the potential for risk due to possible failure of the instruments preventing RCIC initiations. Therefore, they meet Criterion 4 of Reference 4.

The RCIC Turbine Exhaust Diaphragm Pressure—High signals are initiated from four pressure transmitters that are connected to the area between the rupture diaphragms on the RCIC turbine exhaust line. Four channels of RCIC Turbine Exhaust Diaphragm Pressure—High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is selected to be low enough to prevent damage to the RCIC turbine.

This Function isolates the Group 10 valves.

3.e, 3.f, 3.g, 3.h, 3.i. Area Temperature—High

Area Temperatures are provided to detect a leak from the RCIC steam piping. The isolation occurs when a very small leak has occurred and is diverse to the high flow instrumentation. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. These Functions are not assumed in any USAR transient or accident analysis, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

Area Temperature—High signals are initiated from thermocouples that are located in the area that is being monitored. Two instruments for each Function monitor each area. Two channels for each area monitored by the Temperature—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two channels for the RCIC equipment room area, two channels for the RCIC steam line tunnel area, and four channels for the RHR equipment room areas (two per area), eight channels for the reactor building pipe chase areas (two per area), and 10 channels for the reactor building general areas (two per area). 1B

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

4.h. Manual Initiation (continued)

This Function isolates the Group 6 and 7 valves.

5. RHR Shutdown Cooling System Isolation

5.a, 5.d, 5.e. Area Temperature—High

Area Temperature—High is provided to detect a leak from the RHR SDC System piping. The isolation occurs when a very small leak has occurred and is diverse to the high flow instrumentation. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. These Functions are not assumed in any USAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

Area Temperature—High signals are initiated from thermocouples that are located in the area that is being monitored. Two instruments for each Function monitor each area/room. Twenty-two channels for Area Temperature—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are four channels for the RHR equipment room areas (two per area), eight channels for the reactor building pipe chase areas (two per area), and 10 channels for the reactor building general areas (two per area). B

The Area Temperature—High Functions are only required to be OPERABLE in MODE 3. In MODES 1 and 2, the Reactor Vessel Pressure—High Function and other administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

The Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

This Function isolates the Group 5 valves.

5.b. Reactor Vessel Water Level—Low, Level 3

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, isolation of some

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS logic bus will not jeopardize steady state power operation. The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance. The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 3).

SR 3.3.8.2.2

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

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

SR 3.3.8.2.3

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.3.2 (continued)

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

SR 3.3.8.3.3

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

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 that these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. USAR, Section 8.3.1.1.3.

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

3. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LA.2 Details of the methods for performing CTS 4.3.1.1, the IRM and APRM CHANNEL CHECK (CTS Table 4.3.1.1-1 Note (b)), the LPRM CHANNEL CALIBRATION (CTS Table 4.3.1.1-1 Note (e)), the APRM Flow-Biased Simulated Thermal Power — Upscale CHANNEL CALIBRATION (CTS Table 4.3.1.1-1 Note (f)), the APRM Flow-Biased Simulated Thermal Power — Upscale CHANNEL FUNCTIONAL TEST (CTS Table 4.3.1.1-1 Note (h)), and CTS 4.3.1.2, the LOGIC SYSTEM FUNCTIONAL TEST, are proposed to be relocated to the Bases. Furthermore, the Bases also describes that the flow units are an integral part of the APRM Flow Biased Simulated Thermal Power — Upscale Function. Thus a CHANNEL FUNCTIONAL TEST and a CHANNEL CALIBRATION Surveillance would have to include the flow units (as required by their associated definitions in ITS Section 1.1). These details are not necessary to ensure the OPERABILITY of the RPS Instrumentation. The requirements of ITS 3.3.1.1 and the associated Surveillance Requirements are adequate to ensure the RPS instrumentation are maintained OPERABLE. Specifically, the SRs continue to require SRM/IRM and IRM/APRM overlap to be verified, the LPRMs to be calibrated, a CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION to be performed on the APRM Flow Biased Simulated Thermal Power — Upscale Function, and LOGIC SYSTEM FUNCTIONAL TESTS to be performed. As such, these 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. B B

LA.3 Requirements for the removal of RPS shorting links in CTS Table 3.3.1-1 Note (b) (including CTS Table 3.3.1-1 footnote *) are proposed to be relocated from the Technical Specifications. The shorting links are required to be removed with any control rod withdrawn from a core cell containing one or more fuel assemblies when SHUTDOWN MARGIN has not been demonstrated and if the Refuel position one-rod-out interlock is not OPERABLE. The primary reactivity control functions during refueling are the refueling interlocks and SHUTDOWN MARGIN. The refueling interlocks are required to be OPERABLE by ITS 3.9.1 and ITS 3.9.2. Although SHUTDOWN MARGIN may not yet have been demonstrated until after CORE ALTERATIONS are completed in MODE 5, SHUTDOWN MARGIN calculations performed prior to altering the core, along with procedural compliance for any CORE ALTERATIONS, provides indication that adequate SHUTDOWN MARGIN is available. In addition to SRM OPERABILITY with shorting links removed, IRM OPERABILITY will continue to provide backup for the credited functions for any significant reactivity excursions. Since the SRM channel high flux scram (with shorting links removed) provides only an uncredited backup in

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.3 (cont'd) MODE 5, the relocation of the shorting link removal requirement does not significantly affect safety. Details for control of shorting link removal will be relocated to the Technical Requirements Manual (TRM). The TRM will be incorporated by reference into the NMP2 USAR at ITS implementation. Changes to the TRM will be controlled by the provisions of 10 CFR 50.59.

LA.4 The LPRM inputs for OPERABILITY of the APRM are proposed to be relocated to the Bases. The Bases states that if sufficient LPRMs are not available (the same number as in CTS Table 3.3.1-1, Note (c)), then the associated APRM is inoperable. As such, these details are not necessary in the RPS Instrumentation Table 3.3.1.1-1. The definition of OPERABILITY suffices. In addition, CTS Table 3.3.1-1 Note (i) states that the Turbine Stop Valve — Closure and the Turbine Control Valve Fast Closure, Valve Trip System Oil Pressure — Low Functions are automatically bypassed based on turbine first stage pressure when THERMAL POWER is less than 30% of RATED THERMAL POWER. This system design detail is proposed to be relocated to the Bases. This is a design detail that is not necessary to include in the Technical Specifications to ensure the OPERABILITY of the RPS Instrumentation, since the OPERABILITY requirements are adequately addressed in ITS 3.3.1.1 and proposed SR 3.3.1.1.15. 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.5 CTS Table 3.3.1-1 Note (e) states the Main Steam Isolation Valve — Closure Function shall be automatically bypassed when the reactor mode switch is not in the Run position, CTS Table 3.3.1-1 Note (g) states that the Drywell Pressure—High Function also actuates the Standby Gas Treatment System, CTS Table 3.3.1-1 Note (j) states that Turbine Stop Valve—Closure and the Turbine Stop Valve Fast Closure, Valve Trip System Oil Pressure—Low Functions also actuate the EOC-RPT System, CTS Table 3.3.1-1 Action 6 states the corresponding turbine first stage pressure associated with 30% RTP, and CTS Table 2.2.1-1 Function 4 describes the Allowable Value in terms of inches "above instrument zero." These system design details are proposed to be relocated to the USAR. These are design details that are not necessary to be included in the Technical Specifications to ensure the OPERABILITY of the RPS instrumentation since OPERABILITY requirements are adequately addressed in ITS 3.3.1.1. 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 USAR will be controlled by the provisions of 10 CFR 50.59. In addition, the Applicabilities for the Turbine Stop Valve — Closure and the

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.5 (cont'd) Turbine Control Valve Fast Closure, Trip Oil Pressure — Low Functions have been modified in ITS Table 3.3.1.1-1 to be ≥ 30% RTP, consistent with the design and CTS Table 3.3.1-1 Note (i).

LA.6 CTS Table 2.2.1-1 Note (a) states that the APRM Flow-Biased Simulated Thermal Power—Upscale scram Allowable Value varies as a function of recirculation loop drive flow (W). This detail of system description is proposed to be relocated to the Bases. ITS 3.3.1.1 and associated SRs will ensure that the Allowable Value is maintained properly. This detail is not necessary to ensure the Allowable Value is maintained properly. As such, this 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.

LD.1 The Frequencies for performing the RPS LOGIC SYSTEM FUNCTIONAL TEST (LSFT) of CTS 4.3.1.2 for all Functions except 2.a, 2.b, 2.c, 2.d, and 2.e (proposed SR 3.3.1.1.13) and the RPS RESPONSE TIME TEST of CTS 4.3.1.3 (proposed SR 3.3.1.1.16) have been extended from 18 months to 24 months to facilitate a change in the NMP2 refueling cycle from 18 months to 24 months. These SRs ensure that RPS logic will function as designed in response to an analyzed event. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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. 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 small. Extending the Surveillance Test interval for the RPS LSFT and RESPONSE TIME TEST is acceptable because the RPS is verified to be operating properly throughout the operating cycle by the performance of CHANNEL CHECKS and, in some cases, CHANNEL FUNCTIONAL TESTS. This testing ensures that a significant portion of the RPS circuitry is operating properly and will detect significant failures of this circuitry. Additional justification for extending the Surveillance Test interval is that the RPS network, including the actuating logic, is designed to be single failure proof and therefore, is highly reliable.

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) Based on the inherent system and component reliability and the testing performed during the operating cycle, the impact, if any, from this change on system availability is small. The review of historical surveillance data also demonstrated that there are no failures that would invalidate this conclusion. 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.

LD.2 The Frequency for performing the CTS 4.3.1.1 CHANNEL FUNCTIONAL TEST for CTS Table 4.3.1.1-1 Functional Unit 11, Reactor Mode Switch—Shutdown Position Function (proposed SR 3.3.1.1.12) has been extended from 18 months to 24 months to facilitate a change in the NMP2 refueling cycle from 18 to 24 months. The Reactor Mode Switch Shutdown Position provides manual trip capability of the Reactor Protection System that is redundant to the automatic protective instrumentation channels and to the Manual Scram pushbuttons. The proposed change will allow this Surveillance to extend its 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 4.0.2 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 4.0.2 and proposed SR 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. Reviews of historical maintenance and surveillance data have shown that this test normally passes its Surveillance 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 small. Extending the Surveillance Test interval for the Reactor Mode Switch—Shutdown Position is acceptable due to the system redundancy and because the RPS System is verified to be operating properly throughout the operating cycle by the performance of CHANNEL CHECKS and CHANNEL FUNCTIONAL TESTS on the other trip functions. This testing ensures that a significant portion of the RPS circuitry is operating properly and will detect significant failures of this circuitry. Additional justification for extending the Surveillance Test interval is that the RPS network, including the actuating logic, is designed to be single failure proof and therefore, is highly reliable. Based on the inherent system and component reliability and the testing performed during the operating cycle, the impact, if any, from this change on system availability is small. The review of historical surveillance data also demonstrated that there are no failures that would invalidate this conclusion. In addition, the proposed

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LD.2 (cont'd) 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

LE.1 The Frequency for performing the CTS 4.3.1.1 CHANNEL CALIBRATION for CTS Table 4.3.1.1-1 Functional Units 1.a, 3, 4, 5, 7, 8.b, 9, and 10 (proposed SR 3.3.1.1.13 for Functions 1.a, 3, 4, 5, 6, 7.b, 8, and 9) has been extended from 18 months to 24 months to facilitate a change in the NMP2 refueling cycle from 18 months to 24 months. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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. The subject SR ensures that the RPS System will function as designed during an analyzed event. Extending the SR Frequency is acceptable because the RPS system along with the RPS initiation logic is designed to be single failure proof and therefore is highly reliable. Furthermore, the impacted RPS instrumentation has been evaluated based on make, manufacturer and model number to determine that the instrumentation's actual drift falls within the design allowance in the associated setpoint calculation. The following paragraphs, listed by CTS Functional Unit number, identify by make, manufacturer and model number the drift evaluations performed:

Functional Unit 1.a, Intermediate Range Monitor (IRM) Neutron Flux—High

This function is performed by a fission chamber, voltage preamplifier, and a mean square voltage-wide range monitor. The equipment is supplied by General Electric. It is required to be OPERABLE in MODES 2 and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies to minimize the consequences of a control rod withdrawal error. During these modes of operation other surveillances are performed more frequently which will detect major deviation in the system. The equipment drift was evaluated utilizing a qualitative analysis. The results of this analysis support 24 month fuel cycle surveillance interval extension.

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LE.1 (cont'd)

Functional Unit 3, Reactor Vessel Steam Dome Pressure—High

This function is performed by Rosemount 1153GB9 Transmitters and Rosemount 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Functional Unit 4, Reactor Vessel Water Level—Low, Level 3

This function is performed by Rosemount 1153DB4 Transmitters and Rosemount 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Functional Unit 5, Main Steam Isolation Valve—Closure

This function is performed by NAMCO EA740 limit switches. Limit switches are mechanical devices that require mechanical adjustment only; drift is not applicable to these devices. Therefore, an increase in surveillance interval to accommodate a 24 month fuel cycle does not affect limit switches with respect to drift.

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LE.1 (cont'd)

Functional Unit 7, Drywell Pressure—High

This function is performed by Rosemount 1153GB5 Transmitters and Rosemount 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Functional Unit 8.b, Scram Discharge Volume Water Level—High, Float Switch

This function is performed by Model 751 float switches manufactured by Magnetrol. These devices are mechanical devices that require mechanical setting at the proper level only; drift is not applicable to these devices. Therefore, an increase in surveillance intervals to accommodate a 24 month fuel cycle does not affect the level switches with respect to drift.

Functional Unit 9, Turbine Stop Valve—Closure

This function is performed by NAMCO EA170 limit switches. Limit switches are mechanical devices that require mechanical adjustment only; drift is not applicable to these devices. Therefore, an increase in surveillance interval to accommodate a 24 month fuel cycle does not affect limit switches with respect to drift.

Functional Unit 10, Turbine Control Valve Fast Closure, Trip Oil Pressure—Low

This function is performed by Static-O-Ring Pressure Switches 9TA-BB5-NX-C1A-JJTTX7. The Static-O-Ring Pressure Switches were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is minimal as a result of the change in the surveillance test interval. A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history, demonstrates that there are no failures that would invalidate the conclusion that the impact, if any on system availability is minimal from a change to a 24 month surveillance frequency. 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.

LE.2 The Frequency for performing the CTS 4.3.1.1 CHANNEL CALIBRATION for CTS Table 4.3.1.1-1 Functional Units 2.a, 2.b, and 2.c (proposed SR 3.3.1.1.13) has been extended from 18 months to 24 months to facilitate a change in the NMP2 refueling cycle from 18 months to 24 months. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 3.0.2). The subject SR ensures that the APRMs will function as designed during an analyzed event. Extending the SR Frequency is acceptable because the APRMs are designed to be single failure proof and therefore are highly reliable. The extension of the Frequency to 24 months is consistent with the General Electric Licensing Topical Report, NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC-PRNM) Retrofit Plus Option III Stability Trip Function," dated October 1995 (approval by the NRC was documented in the NRC Safety Evaluation Report (SER) dated September 5, 1995). As indicated in NEDC-32410P-A, Section 8.3.4.3.3, calibration interval is generally determined by drift of analog components, the number of which was significantly reduced by the replacement of the APRMs with the NUMAC-PRNM. In the NUMAC-PRNM, the only analog components that remain for the main signal processing are input isolation amplifiers, a sample-and-hold circuit, and an A/D converter. These analog components are highly reliable and very stable with virtually no drift. In addition, the sample-and-hold circuit and A/D converters are tested as part of the automatic self-test. The NUMAC-PRNM replaced all analog processing hardware, including that used for flow processing, with digital processing that has no drift. Any digital failures will be identified by the automatic self-test, Channel Checks, or in very rare cases by the Channel Functional Test. The results of the NRC review of this GE analysis as it relates to NMP2 is documented in the NRC SER dated March 31, 1998, (including the correction dated April 15, 1998). The SER

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LE.2 (cont'd) concluded that the GE analysis is applicable to NMP2. The SER allowed NMP2 to extend its old CHANNEL CALIBRATION Surveillance Frequency from 184 days to 18 months, since 18 months is the current refueling cycle. Therefore, since the GE analysis supports a 24 month CHANNEL CALIBRATION Surveillance Frequency, this change is considered acceptable.

"Specific"

L.1 During normal operation in MODES 3 and 4, all control rods are fully inserted and the Reactor Mode Switch Shutdown position control rod withdrawal block (ITS 3.3.2.1) does not allow any control rod to be withdrawn. Under these conditions, the RPS function is not required to be OPERABLE; therefore the IRM, Reactor Mode Switch Shutdown Position; and Manual Scram requirements for MODES 3 and 4 (CTS Tables 3.3.1-1 and 4.3.1.1-1 Functional Units 1, 11, and 12) have been deleted. The Actions associated with these Functions for MODES 3 and 4 are also deleted (CTS Table 3.3.1-1 Actions 2, 7, and 8). Special Operations LCO 3.10.3 and LCO 3.10.4 will allow a single control rod to be withdrawn in MODES 3 or 4 by allowing the Reactor Mode Switch to be in the Refuel position. Therefore, the IRM MODES 3 and 4 RPS requirements have been included in LCO 3.10.3 and LCO 3.10.4.

L.2 CTS Tables 3.3.1-1 and 4.3.1.1-1 require Functional Units 1.a, 1.b, 11, and 12 (IRM Neutron Flux—High, IRM Inoperative, Reactor Mode Switch—Shutdown Position, and Manual Scram) to be OPERABLE in MODE 5. ITS 3.3.1.1 only requires these Functions to be OPERABLE in MODE 5 when a control rod is withdrawn from a core cell containing one or more fuel assemblies (ITS Table 3.3.1.1-1 Note (a)). Control rods withdrawn from or inserted into a core cell containing no fuel assemblies have a negligible impact on the reactivity of the core and therefore are not required to be OPERABLE with the capability to scram. Provided all rods otherwise remain inserted, the RPS Functions serve no purpose and are not required. In this condition the required SHUTDOWN MARGIN (ITS 3.1.1) and the required one-rod-out interlock (ITS 3.9.2) ensure no event requiring RPS will occur. This change is also similar to the allowance provided in CTS Table 3.3.1-1 Note (h) and CTS Table 4.3.1.1-1 Note (m) for Functional Units 8.a and 8.b (Refer to Discussion of Change L.5 below for further discussion). In addition, CTS Table 3.3.1-1 Actions 3 and 9, as they apply to Functional Units 1.a, 1.b, 11, and 12, have also been modified in ITS 3.3.1.1 ACTION H to be consistent with the new Applicability. Currently, Core Alterations are required to be suspended and all insertable control rods must be inserted. Since all control rods are required to be fully inserted during fuel movement (enforced by ITS 3.9.1), the proposed

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L.2 (cont'd) Applicability cannot be entered while moving fuel. Thus, the only possible Core Alteration is control rod withdrawal, which is adequately addressed in ITS 3.3.1.1 ACTION H. Furthermore, CTS Table 3.3.1-1 Action 9 also requires the reactor mode switch to be locked in Shutdown. This Action has also been deleted since the proposed Applicability only requires the control rods to be inserted (i.e., once the control rods are inserted, the RPS Functions are no longer required to be OPERABLE, thus there is no need to place the reactor mode switch in Shutdown). This is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1.

L.3 Trip setpoints listed in CTS Table 2.2.1-1, (including footnote *) and CTS Table 3.3.1-1 Action 6, footnote *, are not included in the ITS and all references to these setpoints in CTS 2.2.1 and CTS 3.3.1 are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.1.1 reflects Allowable Values consistent with the philosophy of NUREG-1434, Rev. 1. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoints will either be in accordance with this Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, these trip setpoints are not required to be in the Technical Specifications to provide adequate protection of the public health and safety. 1 B

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.4 The Main Steam Line Radiation—High RPS Function (CTS Tables 2.2.1-1, 3.3.1-1, and 4.3.1.1-1 Functional Unit 6, including Table 3.3.1-1 Note (d) and Table 4.3.1.1-1 Note (j)) and its associated Action (CTS Table 3.3.1-1 Action 5) and Surveillance Requirements is proposed to be deleted. In addition, the Main Steam Line Radiation — High Function for CTS 3.3.2, Isolation Actuation Instrumentation, is proposed to be deleted from the Technical Specifications. This is described in Discussion of Change L.6 for ITS 3.3.6.1. This proposed deletion of the scram function is based on the BWR Owners' Group Licensing Topical Report NEDO-31400A dated July 9, 1987, the NRC Safety Evaluation Report (SER) for that document, and the information provided in this Discussion Of Change. Eliminating the Main Steam Line Radiation Monitor automatic reactor shutdown feature and Main Steam Isolation Valve (MSIV) isolation will result in the reduced potential for unnecessary plant transients caused by spurious Main Steam Line Radiation Monitor (MSLRM) actuation trips and will increase plant operational flexibility.

The Main Steam Line Radiation Monitoring System consists of four redundant radiation monitors located above the main steam lines in the main steam tunnel. The Main Steam Line Radiation Monitoring System was designed to provide an early indication of gross fuel failures. The original intention was to mitigate the release of activity due to a fuel failure by providing a scram signal to terminate the initiating event and a MSIV closure signal to assure containment of the release. However, no credit is taken for these signals in any design basis event for terminating the initiating event or assuring the release remains within accepted limits. The only design basis accident in which either the Main Steam Line Radiation Monitoring System scram or MSIV isolation functions are mentioned is the control rod drop accident. To be consistent with the requirements of Section 15.4.9 of the Standard Review Plan, all of the postulated radioactivity released from this accident is assumed to be released to the turbine and condenser before the isolation occurs. Hence, the isolation resulting from the Main Steam Line Radiation Monitors provides no benefit.

The NRC staff has concluded that removal of the Main Steam Line Radiation Monitoring System trips that automatically shutdown the reactor and close the MSIVs is acceptable and that Licensing Topical Report, NEDO-31400A may be referenced in support of an amendment request provided that:

a.) The applicant demonstrates that the assumptions with regard to input values (including power per assembly and X/Q, and decay times) that are made in the generic analysis of the Licensing Topical Report bound those for the plant.

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L.4 (cont'd)

Table 1 of this Discussion of Change provides a comparison of key input parameters and Table 2 compares the dose assessment between the NMP2 Updated Safety Analysis Report and the NEDO-31400A analysis assumptions. The higher power level for NMP2 is used to determine the source term. Other considerations enter into the final two hour Exclusion Area Boundary Dose, such as the atmospheric dispersion factor, X/Q. In this case the X/Q is approximately a factor of ten less than the NEDO-31400A values which more than offsets the higher power level for NMP2. All other parameters are the same or more conservative than the NEDO-31400A values. Tables 1 and 2 demonstrates that the generic analysis of the Licensing Topical Report is bounding for NMP2.

b.) The applicant includes sufficient evidence (implemented or proposed operating procedures, or equivalent commitments) to provide reasonable assurance that significantly increased radioactivity levels in the main steam lines will be controlled expeditiously to limit both occupational and environmental releases.

NMP2 has, in place, procedures that ensure that any significant increase in the levels of radioactivity in the main steam lines is promptly controlled to limit environmental releases and on-site occupational exposures. NMP2 plant procedures will be enhanced to incorporate the considerations of this Technical Specification Amendment.

c.) The applicant standardizes the Main Steam Line Radiation Monitor and offgas radiation monitor setpoints at 1.5 times the Nitrogen-16 background dose rate at the monitor locations, and commits to promptly sample the reactor coolant for possible contamination if the MSLRM and/or the offgas radiation monitors exceed their alarm setpoint.

The Main Steam Line Radiation Monitor alarm setpoint is 1.5 times the Nitrogen-16 background at the monitor location. That alarm will trigger entry into a procedure which will require a reactor coolant sample to be obtained and analyzed. The offgas pretreatment monitor alarm/trip is set in accordance with the Offsite Dose Calculation Manual to satisfy CTS 3.11.2.7 (ITS 3.7.4). The Technical Specification basis for the setpoint is that, restricting the gross activity rate of noble gases from the main condenser offgas provides reasonable assurance that the

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd)

total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. CTS 3.11.2.7 (ITS 3.7.4) implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR 50.

Reasonable assurance is provided in the plant response to increased radiation levels as detected by the offgas pretreatment monitor. The pretreatment monitor is more sensitive to detecting noble gas activity than the Main Steam Line Radiation Monitor because the Nitrogen-16 source, dominating the radiation present at the Main Steam Line Radiation Monitor, has decayed prior to the pretreatment monitor. The offgas pretreatment radiation monitor alarm/trip setpoint is based on CTS 3.11.2.7 (ITS 3.7.4). As required by CTS 3.11.2.7 (ITS 3.7.4), a level of 350,000 μCi/sec as measured downstream of the recombiner will require restoring the radioactivity rate to within its limit within 72 hours or, within the next 12 hours, be in at least HOT SHUTDOWN. The response to the more sensitive pretreatment monitor will ensure that actions are taken to limit occupational doses and environmental releases.

The elimination of the scram function associated with the MSLRM will reduce the likelihood of an inadvertent scram. Specifically, the plant is vulnerable to unnecessary scrams caused by Nitrogen-16 spikes or other spurious signals that can trip this circuit. This is especially true when reactor scram instrumentation calibration is in progress since this work involves a half scram signal. Spurious signals affecting the remaining channel can result in a full scram signal with a resultant reactor trip. As noted in the topical report, eight scrams industry wide have been attributed to the Main Steam Line Radiation Monitor between 1980 and 1987, representing 162 plant operating years. Unnecessary scrams present a plant upset that challenges safety functions. Further, as reported in the topical report, the reduction in scram frequency has economical benefit in avoiding an unnecessary scram and the associated plant recovery lost time.

NEDO-31400A results indicate that removing the scram and main steam line isolation function will represent a reduction in transient initiating events which results in a 0.3% reduction in core damage frequency probability. The NMP2 Individual Plant Examination (SAS-TR-92-001, Revision 0) was referenced as a comparison to the above NEDO-31400A results. The NMP2 results yielded a

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L.4 (cont'd) 0.2% reduction in core damage frequency and a 0.5% reduction in early high radionuclide release frequency. Hence, the final result is a net improvement in safety.

The referenced topical report also evaluated the impact that removal of these functions would have on reactivity control system failure frequency. The results were a negligible increase (1.4E-09 events per year), which is offset by the relative large reduction in core damage frequency. Hence, the final result is a net improvement to safety.

Based on the above evaluation, the proposed change satisfies the criteria of NEDO-31400A for deletion of the MSLRM scram function. Therefore, the proposed change is acceptable.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

TABLE 1

CONTROL ROD DROP ACCIDENT
COMPARISON OF KEY ANALYSIS INPUT VALUES
NEDO-31400A VS. NMP 2

PARAMETER	NEDO-31400A VALUE[1]	NMP2 UPDATED SAFETY ANALYSIS REPORT
Number of Failed Fuel Rods	850	770
Core Average Power (MWt)	1579	3536 (102%)
Relative Power Level of Failed Rods (fraction)	1.5	1.5
Power Level of Failed Rods (MWt)	0.12	0.11
Fission Product Release from Melted Rods MELTED NON-MELTED	 100% NG/50% Iodines 10% NG/10% Iodines	 100% NG/50% Iodines 10% NG/10% Iodines 30% Kr-85 (R.G. 1.25)
Mass Fraction of Melted Fuel	0.0077	0.0077
% of Fission Products Transported to Main Condenser	100% NG/10% Iodines	100% NG/10% Iodines
% Airborne of Fission Products in Main Condenser	100% NG/10% Iodines	100% NG/10% Iodines
Main Condenser Leakage[2]	1 % per day	1 % per day
Hydrogen Flow Rate to Recombiner - (Design Capability)	50-150 scfm	136 scfm
Air/Noble Gas Offgas Flow Rate	site specific	40 scfm
Thyroid Dose Conversion Factor	Regulatory Guide 1.109	TID-14844
Breathing Rates	Regulatory Guide 1.3	Regulatory Guide 1.3
Whole Body Dose Conversion Factor (Semi-Infinite Cloud)	Regulatory Guide 1.109	TID-14844
Radiological Consequences Evaluation Computer Code	CONACO3	DRAGON code
Dispersion Coefficient, X/Q 0-2 hour Exclusion Area Boundary [2] 0-2 hour Exclusion Area Boundary [3]	 2.5E-03 sec/m^3 3.0E-04 sec/m^3	 1.90E-04 sec/m^3 2.97E-05 sec/m^3
Charcoal Bed Holdup Times[3,4]	Kr = 20 Hours Xe = 15 days	Kr = 26.6 hours Xe = 20 days

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TABLE 1 (continued)

FOOTNOTES:

1. Except as noted in 2 and 3 below, values apply to the Control Rod Drop Accident (CRDA) both with MSIV isolation and without MSIV isolation.

2. Applies only to CRDA with MSIV isolation.

3. Applies only to CRDA without MSIV isolation and 100% of Noble Gas source term processed though the Offgas Treatment System.

4. For a CRDA without MSIV isolation, 100% of the Noble Gases are held-up in the Offgas Treatment system charcoal beds for a time; the Iodines are retained indefinitely in the charcoal beds.

TABLE 2

CONTROL ROD DROP ACCIDENT DOSE COMPARISON
NMP2 DESIGN BASIS VS. NEDO-31400A

Two Hour Exclusion Area Boundary	With Main Steam Line Isolation Updated Safety Analysis Report		NEDO- 31400A		Without Main Steam Isolation Updated Safety Analysis Report		NEDO-31400A	
	Dose (Rem)	% [1]	Dose (Rem)	% [1]	Dose (Rem)	% [1]	Dose (Rem)	% [1]
Whole Body	2.07E-02	0.35	3.1E-01	5.17	1.9E-02	0.32	5.5E-01	9.17
Thyroid	3.34E-01	0.45	4.3E+00	5.73	N/A	N/A	N/A	N/A

FOOTNOTE:

1. Percent of 25% of 10 CFR 100 (or 6 Rem Whole Body and 75 Rem Thyroid)

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.5 The Applicability of CTS Table 3.3.1-1 Functional Units 8.a and 8.b, including Note (h), and Table 4.3.1.1-1 Functional Units 8.a and 8.b, including Note (m), has been modified to only require ITS Table 3.3.1.1-1 RPS Functions 7.a and 7.b to be OPERABLE in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. In addition, ITS 3.3.1.1 ACTION H for MODE 5 only requires action to be initiated to fully insert control rods in core cells containing one or more fuel assemblies. Control rods withdrawn from or inserted into a core cell containing no fuel assemblies have a negligible impact on the reactivity of the core and therefore are not required to be OPERABLE with the capability to scram. Provided all rods otherwise remain inserted, the RPS Functions serve no purpose and are not required. In this condition the required SHUTDOWN MARGIN (ITS 3.1.1) and the required one-rod-out interlock (ITS 3.9.2) ensure no event requiring RPS will occur. The Action for these inoperable Functions in MODE 5 (CTS Table 3.3.1-1 Action 3) is also revised to be consistent with the proposed Applicability. Currently, Core Alterations are required to be suspended and all insertable control rods must be inserted. Since all control rods are required to be fully inserted during fuel movement (enforced by ITS 3.9.1), the proposed Applicability cannot be entered while moving fuel. The only possible Core Alteration is control rod withdrawal, which is adequately addressed by ITS 3.3.1.1 ACTION H.

L.6 The CTS Table 3.3.1-1 Action 6 requirement to initiate a reduction in THERMAL POWER within 15 minutes has been deleted. Immediate power reduction may not always be the conservative method to assure safety. ITS 3.3.1.1 Required Action E.1, which requires the unit to be < 30% RTP within 4 hours (see Discussion of Change L.7 below), ensures prompt action is taken to exit the Applicability due to the inoperability of the associated RPS Functions.

L.7 The time to reach < 30% RTP has been extended from 2 hours (CTS Table 3.3.1-1 Action 6) to 4 hours (ITS 3.3.1.1 Required Action E.1). This extension provides the necessary time to decrease power in a controlled and orderly manner that is within the capabilities of the unit, assuming the minimum required equipment is OPERABLE. This extra time is an acceptable exchange in risk; the risk of an event during the additional period for the unit to be < 30% RTP, versus the potential risk of a unit upset that could challenge safety systems resulting from a rapid power reduction. This time is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1.

L.8 A Note to SR 3.3.1.1.4 and Note 2 to SR 3.3.1.1.13 are being added to exempt the CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION requirements of CTS 4.3.1.1 until 12 hours after entering MODE 2 from

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L.8 (cont'd) MODE 1. The IRM Neutron Flux — Upscale and Inoperable Functions and the APRM Neutron Flux — Upscale, Setdown Function are required in MODE 2, but not in MODE 1, and the required Surveillances cannot be performed in MODE 1 (prior to entry in the applicable MODE 2) without utilizing jumpers or lifted leads. Use of these devices is not recommended since minor errors in their use may significantly increase the probability of a reactor transient or event which is a precursor to a previously analyzed accident. Therefore, time is allowed to conduct the SRs after entering the applicable MODE. This is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1.

L.9 A Note is being added to the APRM heat balance calibration (CTS Table 4.3.1.1-1 Note (g), proposed SR 3.3.1.1.3) that states the Surveillance is not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. This is allowed because it is difficult to accurately determine core THERMAL POWER from a heat balance < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large inherent margin to thermal limits (MCPR and APLHGR).

L.10 Note 2 has been added to CTS 4.3.1.3 (proposed SR 3.3.1.1.16) that exempts the sensors for the Reactor Vessel Steam Dome Pressure — High and Reactor Vessel Water Level — Low, Level 3 Functions from response time testing and allows the design sensor response time to be used in the determination of the RPS RESPONSE TIME. Deletion of the response time test for these sensors was evaluated in NEDO-32291 "System Analysis for Elimination of Selected Response Time Testing Requirements," January 1994, and was determined to be acceptable provided the individual licensee referencing this NEDO in a plant specific license amendment request met several conditions stipulated in the generic SER approving NEDO-32291. The evaluation provided below is consistent with the guidance provided in the Staff's generic SER for NEDO-32291.

NMPC has performed a review of NEDO-32291 and determined that the NEDO generic analysis is applicable to NMP2. The equipment affected by the proposed change in the Technical Specifications are the RPS Functions identified above. Prior to installation of a new transmitter/switch or following refurbishment of a transmitter/switch a hydraulic response time test will be performed to determine an initial sensor specific response time value. Applicable NMP2 procedures have been revised/written, as appropriate, to fulfill this recommendation. NMP2 currently does not utilize any transmitters or switches that use capillary tubes in any application that requires response time testing. Therefore, the recommendation that capillary tube testing be performed after initial installation and after any maintenance or modification

TECHNICAL CHANGES - LESS RESTRICTIVE

L.10 (cont'd) activity that could damage the lines for transmitters and switches that use capillary tubes is not applicable to NMP2. Applicable calibration procedures have been revised, as appropriate, to include steps to input a fast ramp or a step change to system components during calibrations. Applicable calibration procedures have been revised, as appropriate, to assure that technicians monitor for response time degradation. In addition, technicians have received appropriate training to make them aware of the consequences of instrument response time degradation. Surveillance test procedures have been revised, as appropriate, to ensure calibrations and functional tests are being performed in a manner that allows simultaneous monitoring of both the input and output response of units under test. NMP2's compliance with the guidelines of Supplement 1 to NRC Bulletin 90-01, "Loss of Fill-Oil in Transmitters Manufactured by Rosemount," was reviewed and documented in a safety evaluation transmitted to NMPC by NRC letter dated January 18, 1995. The NRC's evaluation concluded that NMP2's responses to Bulletin 90-01 and Supplement 1 conform to the requested actions of the Bulletin. The elimination of response time testing does not affect NMPC's response to the Bulletin. The RPS components for which response time testing is proposed to be eliminated has been evaluated and found to be acceptable in NEDO-32291. NMPC has reviewed the vendor recommendations for these components and confirmed that they do not contain periodic response time testing requirements.

The application of the proposed footnote will allow NMPC to use design response time data for the sensor in the determination of the system response time, and eliminate the requirement for a separate measurement of the sensor response time. The remainder of the channel will continue to be tested for response time. Other Technical Specification testing requirements such as CHANNEL CALIBRATION, CHANNEL FUNCTIONAL TEST, CHANNEL CHECK, AND LOGIC SYSTEM FUNCTIONAL TEST in conjunction with actions taken in response to NRC Bulletin 90-01 are sufficient to identify failure modes or degradations in instrument response times and assure operation of the analyzed instrument loops within acceptable limits. The elimination of the response time testing of the identified sensors will reduce the potential for inadvertent actuation of the RPS. Accordingly, this change will reduce the likelihood of a plant transient due to an inadvertent scram.

Accordingly, based on the above evaluation, which is consistent with the guidelines of the Staff's generic SER approving NEDO-32291, the proposed elimination of sensor response time is acceptable. The above change is similar to that approved by the NRC in License Amendment No. 184 for Brunswick Units 1 & 2.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 3.0.2). The subject SR ensures that the RBM System will function as designed during an analyzed event. Extending the SR Frequency is acceptable because the RBM System is designed to be single failure proof and therefore is highly reliable. The extension of the Frequency to 24 months is consistent with the General Electric Licensing Topical Report, NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC-PRNM) Retrofit Plus Option III Stability Trip Function," dated October 1995 (approval by the NRC was documented in the NRC Safety Evaluation Report (SER) dated September 5, 1995). As indicated in NEDC 32410P-A, Section 8.5.4.3.3, calibration interval is generally determined by drift of analog components. In the NUMAC-PRNM, all analog processing is limited to the APRM (LPRM and flow input processing). The RBM performs all calculations digitally, and therefore is not subject to drift. These are already covered by Channel Functional Tests and automatic self-test in the APRM. Further, any drift in the LPRM signals is nulled out as part of the RBM logic which looks only for change over a short period of time. The results of the NRC review of the GE analysis as it relates to NMP2 is documented in the NRC Safety Evaluation Report (SER) dated March 31, 1998, (including the correction dated April 15, 1998). The SER concluded that the GE analysis is applicable to NMP2. The SER allowed NMP2 to extend its old CHANNEL CALIBRATION Surveillance Frequency from 92 days to 18 months, since 18 months is the current refueling cycle. Therefore, since the GE analysis supports a 24 month CHANNEL CALIBRATION Surveillance Frequency, this change is considered acceptable.

"Specific"

L.1 Trip setpoints listed in CTS Table 3.3.6-2 are not included in the ITS and all references to these setpoints in CTS 3.3.6 and CTS 3.3.6 Action a are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.2.1 reflects Allowable Values consistent with the philosophy of NUREG-1434, Rev. 1. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, 1 B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoints will either be in accordance with this Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, these trip setpoints are not required to be in the Technical Specifications to provide adequate protection of the public health and safety.

L.2 A note has been added to the CTS Table 4.3.6-1 CHANNEL FUNCTIONAL TEST Surveillance for Trip Function 6.a, the Reactor Mode Switch Shutdown Position (proposed SR 3.3.2.1.6), which will allow one hour to perform the CHANNEL FUNCTIONAL TEST after placing the reactor mode switch in the shutdown position. Performing the test with the reactor mode switch in another position requires the use of jumpers, lifted leads, or movable links, which could cause an unplanned transient at power if not done correctly. This change will eliminate the need to perform these operations during conditions where the rod block is not required (Modes 1 and 2) and therefore is considered safer. This change will permit entry into MODES 3 and 4 if the 24 month Frequency is not met per SR 3.0.2, therefore, the change is considered less restrictive. This Frequency is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1.

L.3 The CTS 3.1.4.1 (ITS 3.3.2.1 and Table 3.3.2.1-1 Function 2) RWM low power setpoint has been reduced from 20% RTP to 10% RTP. Amendment 17 to NEDE-24011-P-A (GESTAR-II) justified reduction of the power level at which the RWM is bypassed from its current value of 20% RTP to 10% RTP. The justification was based on the fact that the analytical basis for this bypass power level is 10% RTP. The NRC Safety Evaluation Report (SER) for

A.1

Specification 3.3.2.2

INSTRUMENTATION

3/4.3.9 ~~PLANT SYSTEMS ACTUATION~~ Feedwater System and Main Turbine High Water Level Trip INSTRUMENTATION

feedwater system and main turbine trip A.2

LIMITING CONDITION FOR OPERATION

LCO 3.3.2.2

3.3.9 The ~~plant systems~~ actuation instrumentation channels shown in Table 3.3.9-1 shall be OPERABLE ~~with their Trip Setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.9-2.~~ L.1

A.3

APPLICABILITY: ~~As shown in Table 3.3.9-1.~~ THERMAL POWER ≥ 25% RTP. L.2

ACTION: feedwater system and main turbine trip A.2

ACTIONS A, B, and C

a. With a ~~plant system actuation~~ instrumentation channel Trip Setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.9-2, declare the channel inoperable and take the action required by Table 3.3.9-1.

ACTIONS A, B, and C

b. With one or more Plant System Actuation Instrumentation channels inoperable take the ACTION required by Table 3.3.9-1.

add proposed ACTIONS Note A.4

SURVEILLANCE REQUIREMENTS feedwater system and main turbine trip A.2

SRs 3.3.2.2.1 through SR 3.3.2.2.3

4.3.9.1 Each ~~plant system~~ actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.9.1-1.

4.3.9.2 LOGIC SYSTEM FUNCTIONAL TESTS and ~~simulated automatic operation~~ of all channels shall be performed at least once per ~~18~~ 24 months. A.5 B LD.1

SR 3.3.2.2.4

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DISCUSSION OF CHANGES
ITS: 3.3.2.2 - FEEDWATER SYSTEM AND MAIN TURBINE HIGH WATER LEVEL TRIP INSTRUMENTATION

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 The Feedwater System/Main Turbine Instrumentation requirements of CTS 3.3.9, Plant Systems Actuation Instrumentation has been placed in ITS 3.3.2.2. The requirements of the Plant Service Water System is being addressed in CTS 3/4.3.9. Since this is only a change in the presentation, this change is considered administrative.

A.3 The CTS 3.3.9 Applicability, which states that the Applicability is as shown in CTS Table 3.3.9-1, has been changed to specifically state the Applicability, instead of referencing a Table. This has been done since a Table format has not been used in the proposed Specification. (See Discussion of Change L.2 below for the change to the actual Applicability). Since this change is a presentation preference only, it is considered administrative.

A.4 This proposed change to the CTS 3.3.9 Actions provides more explicit instructions for proper application of the Actions for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," the ITS 3.3.2.2 ACTIONS Note ("Separate Condition entry is allowed for each...") provides direction consistent with the intent of the existing Actions for an inoperable feedwater system/main turbine high water level instrumentation channel. It is intended that each inoperable channel is allowed a certain time to complete the Required Actions. Since this change only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A.5 CTS 4.3.9.2 requires performance of "simulated automatic operation." Verification of simulated automatic operation is normally conducted with the system functional test. However, for the Feedwater System and Main Turbine High Water Level Trip Instrumentation, the only automatic operation required is opening of the feedwater pump breakers and closing of the main turbine stop valves. Since no separate system functional test is specified, the operation of these breakers and valves is specifically identified and included with the LOGIC SYSTEM FUNCTIONAL TEST of proposed SR 3.3.2.2.4. Since this is only a change in the presentation, this change is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A Surveillance has been added (proposed SR 3.3.2.2.1) to perform a CHANNEL CHECK every 12 hours of the feedwater and main turbine high water level trip instrumentation. This will ensure that a gross failure of the instrumentation will not remain undetected. This is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1, and is an additional restriction on plant operation.

M.2 The allowable outage time specified in CTS Table 3.3.9-1 Action 140.b for two inoperable channels has been decreased from 72 hours to 2 hours in ITS 3.3.2.2 ACTION B, consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. This 2 hour Completion Time is consistent with ITS 3.2.2 since this instrumentation's purpose is to preclude a MCPR violation. This change is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of CTS 4.3.9.2 (proposed SR 3.3.2.2.4) has been extended from 18 months to 24 months to facilitate a change to the NMP2 refueling cycle from 18 months to 24 months. This surveillance ensures the Feedwater System/Main Turbine High Water Level trip function will operate properly during the corresponding transients of the USAR where this function is required such as a Feedwater Controller Failure. 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 4.0.2 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 4.0.2 and proposed SR 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. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance at the current Frequency. An evaluation has been performed using this data, and it has been determined that the effect on safety

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) due to the extended Surveillance Frequency will be small. The Feedwater System/Main Turbine High Water Level trip function is tested on a more frequent basis during the operating cycle in accordance with a CHANNEL CHECK (proposed SR 3.3.2.2.1) and the CHANNEL FUNCTIONAL TEST (proposed SR 3.3.2.2.2). These surveillances will detect significant failures of the circuitry. In addition, since these water level channels provide indication to the control room (Panel H13-P603A), deviations will be detected and repaired during plant operation.

Based on the Feedwater System/Main Turbine High Water Level trip circuit design, other surveillances performed during the operating cycle and the ability to detect deviations during operation, and the review of historical and surveillance data, it is shown that the impact, if any, on system availability is small as a result of this change. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

LE.1 The Frequency for performing the CHANNEL CALIBRATION Surveillance of CTS 4.3.9.1 and Table 4.3.9.1-1 Trip Function 1.a (proposed SR 3.3.2.2.3) has been extended from 18 months to 24 months to facilitate a change to the NMP2 refueling cycle from 18 months to 24 months. 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 4.0.2 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 4.0.2 and proposed SR 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.

The CHANNEL CALIBRATION Surveillance is performed to ensure that at a previously evaluated setpoint actuation takes place to provide the required safety function. Extending the SR Frequency is acceptable because the instrumentation purchased for these functions are highly reliable and meet the design criteria of safety related equipment. The instrumentation is designed with redundant and independent channels which provide means to verify proper instrumentation performance during operation, and adequate redundancy to ensure a high confidence of system performance even with the failure of a single component.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) Furthermore, the impacted Feedwater System and Main Turbine High Water Level Trip Instrumentation have been evaluated based on manufacturer and model number to determine that the instrumentation's actual drift falls within the assumed design allowance in the associated setpoint calculation. This function is performed by Rosemount 1153DB4 differential pressure transmitters, Bailey 766 Signal Resistor Units (SRUs), and Bailey 745 bistable switches. The bistable switches are functionally checked (proposed SR 3.3.2.2.2) and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Bailey bistable switches with respect to drift. The Bailey SRUs are non calibratable devices and were evaluated utilizing a qualitative analysis (i.e, engineering judgment). The Rosemount transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for this instrument.

Based on the design of the instrumentation and drift evaluations, it is concluded that the impact, if any, on system availability is minimal as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history demonstrates that there are no failures that would invalidate the conclusion that the impact, if any, on system availability is minimal from a change to a 24-month surveillance frequency. 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"

L.1 The Feedwater System/Main Turbine Trip System trip setpoint listed in CTS Table 3.3.9-2 and referenced in CTS 3.3.9 is not included in the ITS and all references to the setpoint in CTS 3.3.9 are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.2.2 reflects the Allowable Value consistent with the philosophy of NUREG-1434, Rev. 1. The Allowable Value has been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoint will either be in accordance with this NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, these trip setpoints are not required to be in the Technical Specifications to provide adequate protection of the public health and safety.

L.2 CTS Tables 3.3.9-1 and 4.3.9.1-1 require the Feedwater System and Main Turbine High Water Level Trip Instrumentation to be OPERABLE in MODE 1. The Feedwater System and Main Turbine High Water Level Trip Instrumentation is provided to ensure that MCPR is maintained above the Safety Limit; however, MCPR is not a concern below 25% RTP due to the large inherent margin that ensures the MCPR Safety Limit is not exceeded, even if a limiting transient occurs. Therefore, the ITS 3.3.2.2 Applicability has been modified to require the instrumentation to be OPERABLE when THERMAL POWER is ≥ 25% RTP, and the current shutdown action specified in Table 3.3.9-1 Actions 140.a and b have been changed to only require power to be reduced to < 25% RTP. In addition, the time to achieve this power level has been reduced from 6 hours to 4 hours, which is consistent with the time provided to exit the Applicability in CTS 3.2.2, MCPR, and NUREG-1434, Rev. 1, and is within the ability of the plant to achieve this condition in a safe manner.

L.3 The details relating to the Instrument Numbers for the Feedwater System/Main Turbine Trip System Instrumentation in CTS Table 3.3.9-1 are proposed to be deleted. These details are not necessary to ensure the Feedwater System/Main Turbine Trip Instrumentation is maintained OPERABLE. The requirements of

TECHNICAL CHANGES - LESS RESTRICTIVE

L.3 (cont'd) ITS 3.3.2.2 (which describes the instrumentation) and the associated Surveillance Requirements are adequate to ensure the required instrumentation is maintained OPERABLE. The Bases also provides a description of the type of instrumentation required by the Specification.

L.4 The CTS Table 3.3.9-1 Actions 140.a and 140.b requirement to restore an inoperable Feedwater System/Main Turbine Trip System channel to OPERABLE status has been changed to allow the channel to be placed in the tripped condition (ITS 3.3.2.2 Required Action A.1 and Required Action B.1) and to continue operations without a requirement to restore the channel (Required Action B.1, which requires restoration of the trip capability, can be performed by placing a channel in trip, as described in the Bases). This allowance for CTS Table 3.3.9-1 Action 140.a essentially changes the current two-out-of-three logic to a one-out-of-two logic, and continues to provide single failure protection. For CTS Table 3.3.9-1, Action 140.b, this allowance restores trip capability such that the Feedwater System/Main Turbine Trip System Function can be met during the time provided to trip the second inoperable channel. This essentially changes the currently allowed two-out-of-two logic (while one channel is inoperable as allowed by CTS Table 3.3.9-1 Action 140.a) to a one-out-of-one logic. This will continue to provide the trip capability.

L.5 CTS Table 3.3.9-1 Action 140 requires reduction in Thermal Power if the Feedwater System/Main Turbine High Water Level Trip Instrumentation is not restored to Operable status. The purpose of the instrumentation is to ensure MCPR limits are not exceeded during a feedwater controller failure, maximum demand event. This is accomplished by tripping the feedwater pumps and main turbine, with the main turbine trip resulting in a subsequent reactor scram. When the instrumentation is inoperable solely due to an inoperable feedwater pump breaker, the unit can continue to operate with the feedwater pump removed from service (NMP2 has three 50% capacity feedwater pumps). Therefore, an additional Required Action is proposed, ITS 3.3.2.2, Required Action C.1, to allow removal of the associated feedwater pump(s) from service in lieu of reducing Thermal Power. This Required Action will only be used if the instrumentation is inoperable solely due to an inoperable feedwater pump breaker, as stated in the Note to ITS 3.3.2.2 Required Action C.1. Since this Required Action accomplishes the functional purpose of the Feedwater System/Main Turbine High Water Level Trip Instrumentation, enables continued operation in a previously approved condition, and still ensures that a MCPR limit will not be exceeded (since the reactor scram is the result of a turbine trip signal, which is not impacted by this change), this change does not have a significant effect on safe operation.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.6 CTS Table 3.3.9-1 Action 140 does not provide any actions when all three Feedwater System/Main Turbine Trip System channels are inoperable. Therefore, a CTS 3.0.3 entry would be required. ITS 3.3.2.2 ACTION B will allow all three channels to be inoperable (ITS 3.3.2.2 Condition B is entered if two "or more" channels are inoperable) for up to 2 hours. The Feedwater System/Main Turbine Trip System Instrumentation is provided to ensure that MCPR is maintained above the Safety Limit. It is overly conservative to require an immediate shutdown when the instrumentation has lost trip capability, because this does not necessarily result in a MCPR limit being violated during a feedwater transient event. In addition, three channels inoperable is essentially equivalent to two channels inoperable (the trip capability is lost) and the CTS allows a limited time to operate with two channels inoperable. Therefore, the Actions for when trip capability is lost have been made consistent with the Actions for when the MCPR limit is not being met and when two channels are inoperable.

A.1

Specification 3.3.3.1

TABLE 4.3.7.5-1 (Continued)

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

* Excludes sensors; sensor comparison shall be done in lieu of sensor calibration. A.5

** Using sample gas containing: A.1

a. One volume percent hydrogen, balance nitrogen.
b. Four volume percent hydrogen, balance nitrogen.

*** The CHANNEL CALIBRATION shall consist of position indication verification using the criteria specified for the Inservice Testing Program. B

† The CHANNEL CALIBRATION shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr and a one point calibration check of the detector below 10 R/hr with an installed or portable gamma source.

†† Red, Green or other indication shall be verified as indicating valve position.

B

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 This proposed change to CTS 3.3.7.5 Action a provides more explicit instructions for proper application of the Actions for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," the ITS 3.3.3.1 ACTIONS Note ("Separate Condition entry is allowed for each....") and the wording for ITS 3.3.3.1 ACTIONS A and C ("one or more Functions with...") provides direction consistent with the intent of the existing Action for an inoperable accident monitoring instrumentation channel. It is intended that each Function is allowed certain times to complete the Required Actions. Since this change only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A.3 The details concerning the technical content of the Special Report specified in CTS 3.3.7.5 Actions 80a, 81a, and 81b are being moved to Chapter 5 of the ITS in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. Any technical changes to this requirement are addressed in the Discussion of Changes for ITS: 5.6.

A.4 The format for ITS 3.3.3.1 includes an ACTION (ITS 3.3.3.1 ACTION D) that directs entry into appropriate Conditions referenced in ITS Table 3.3.3.1-1 when two or more channels in the same Function are inoperable and the Completion Time for restoration of all but one required channel has expired (i.e., ITS 3.3.3.1 ACTION C). This change represents a presentation preference only and is, therefore, considered administrative.

A.5 The details in CTS Table 4.3.7.5-1 footnote * related to how to perform the CHANNEL CALIBRATION of thermocouples is deleted since it is duplicative of the definition of CHANNEL CALIBRATION in Chapter 1 of the ITS. This change is considered administrative since there is no change in the calibration method.

RELOCATED SPECIFICATIONS

R.1 Suppression Chamber Air Temperature (CTS Table 3.3.7.5-1 Function 6) is not credited as Category 1 or Type A variable as summarized in the Table 7.5-2 of the USAR. Further, the loss of this instrument is a non-significant risk contributor to core damage frequency and offsite release. Therefore, the requirements specified for this Function did not satisfy the NRC Policy Statement Technical Specification screening criteria as documented in the Application of Selection Criteria to the NMP2 Technical Specifications and have been relocated to the Technical Requirements Manual (TRM). The TRM will be incorporated by reference into the NMP2 USAR at ITS implementation. Changes to the TRM will be controlled in accordance with 10 CFR 50.59.

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 CTS 4.3.7.5 and Table 4.3.7.5-1 require a CHANNEL CALIBRATION of the drywell oxygen concentration analyzers, Instrument 9, once per 18 months. The current maintenance history of this Function does not support an 18 month CHANNEL CALIBRATION Frequency. Therefore, the ITS will require the CHANNEL CALIBRATION Frequency in proposed SR 3.3.3.1.2 for the drywell oxygen concentration analyzers (ITS Table 3.3.3.1-1, Function 10) to be once per 92 days. This change represents an additional restriction on plant operations and achieves consistency with the calibration Frequency supported by the maintenance history.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Details of the method for performing the CHANNEL CALIBRATIONS specified in CTS Table 4.3.7.5-1 footnotes **, ***, and †, (for the Drywell Hydrogen Concentration Analyzers, PCIV Position Indications, and Drywell Radiation Monitors, respectively) and the CHANNEL CHECK specified in the CTS Table 4.3.7.5-1 footnote †† (for the PCIV Position Indications) are proposed to be relocated to the Bases. These requirements proposed to be relocated are procedural details that are not necessary for assuring the OPERABILITY of the instruments. The Surveillance Requirements of ITS 3.3.3.1 provide adequate assurance the specified instruments are maintained OPERABLE. As such, 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.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LE.1 The Frequency for performing the CHANNEL CALIBRATION Surveillances of CTS 4.3.7.5 (proposed SR 3.3.3.1.3) and Table 4.3.7.5-1 for all Functions except for Instrument 10 (ITS Table 3.3.3.1-1 Function 9) has been extended from 18 months to 24 months to facilitate a change to the NMP2 refueling cycle from 18 months to 24 months. 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 4.0.2 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 4.0.2 and proposed SR 3.0.2). The CHANNEL CALIBRATION Surveillance is performed to ensure that the indication is accurate to provide the required safety function. Extending the SR Frequency is acceptable because the PAM instruments are designed to be single failure proof and highly reliable.

Furthermore, the impacted PAM instrumentation has been evaluated based on make, manufacturer and model number to determine that the instrumentation's actual drift falls within acceptable allowances as determined by quantitative or qualitative analysis. The following paragraphs, listed by CTS Instrument number, identify by make, manufacturer and model number the drift evaluations performed:

Instrument 1, Reactor Vessel Pressure

This function is performed by Rosemount 1153GB9 Transmitters and Tracor Westronic D4GE-NSR Recorders. The Tracor Westronics Recorders were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 2, Reactor Vessel Water Level

This function is performed by Rosemount 1153DB5 Transmitters, Rosemount 510DU Master Trip Units, Bailey 766 Signal Resistor Units (SRUs), GE Type 180 Indicators, Tracor Westronics D4GE-NSR Recorders, and a Tracor Westronics 54N-NSR Recorder. The Bailey SRUs are non calibratable devices. The Bailey SRUs, GE Type 180 Indicators, Tracor Westronics recorders, and Rosemount trip unit auxiliary analog output were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters were evaluated by quantitative analysis and the results indicate that the

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 3, Suppression Pool Water Level

This function is performed by Rosemount 1153DB4 Transmitters, Rosemount 1153DB5 Transmitters, GE Type 180 Indicators, Foxboro 2AI-I3V I/E converters, and a Tracor Westronics T4N recorder. The GE Type 180 indicators and the Tracor Westronics recorder were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters and the Foxboro converters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 4, Suppression Pool Water Temperature

This function is performed by Pyco 122-7039-01-314 platinum RTDs (100 ohm), Foxboro 2AI-P2V Ohm/E Converters, GE Type 180 indicators and Tracor Westronics T4N recorders. The RTDs are non calibratable devices. The Pyco RTDs, GE Type 180 indicators and the Tracor Westronics recorders were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Foxboro converters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 5, Suppression Chamber Pressure

This function is performed by Rosemount 1153GB7 Transmitters, Foxboro 2AI-I3V I/E Converters, a GE Type 180 Indicator, and a Tracor Westronics T4N Recorder. The GE Type 180 indicator and the Tracor Westronics recorder were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters and the Foxboro converters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

Instrument 7, Drywell Pressure

This function is performed by Rosemount 1153GB7 Transmitters, Rosemount 1153GB5 Transmitters, Foxboro 2AI-I3V I/E Converters, GE Type 180 Indicators, and Tracor Westronics T4N Recorders. The GE Type 180 indicators and the Tracor Westronics recorders were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters and the Foxboro converters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 8, Drywell Air Temperature

This function is performed by a Pyco 122-4030-04-2.7-6 platinum RTDs (100 ohm), Foxboro 2AI-P2V Ohm/E Converters, and Tracor Westronics T4N Recorders. The RTDs are non calibratable devices. The Pyco RTDs and the Tracor Westronics recorders were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Foxboro converters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 11, Drywell Radiation (High Range)

This function is performed by Kaman KDI ion chamber detectors, Kaman KMA-I1000 ion detector area monitors, Kaman KEM-A Local Microprocessors, Kaman KERIC Remote Indication and Control Units, and Tracor Westronics D4N Recorders. The Kaman Radiation Monitoring Instrumentation and the Tracor Westronics recorders were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The results of this analysis support a 24 month fuel cycle surveillance interval extension.

Instrument 12, PCIV Position

This function is performed by limit switches. Limit switches are mechanical devices that require mechanical adjustment only; drift is not applicable to these devices. Therefore, an increase in surveillance interval to accommodate a 24 month fuel cycle does not affect limit switches with respect to drift.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is minimal as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history demonstrates that there are no failures that would invalidate the conclusion that the impact, if any, on system availability is minimal from a change to a 24-month surveillance frequency. 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"

L.1 A Note has been added to CTS 4.3.7.5 (ITS 3.3.3.1 Note 2 to the Surveillance Requirements) to allow a channel to be inoperable for up to 6 hours solely for performance of required Surveillances provided the other channel in the associated Function is OPERABLE. The 6 hour testing allowance has been granted by the NRC in TS amendments for Georgia Power Company's Hatch Unit 1 (amendment 185) and Unit 2 (amendment 125) and Washington Public Power Supply System's WNP-2 (amendment 149, the ITS amendment). The NRC has also granted this allowance in other topical reports for the Reactor Protection System, Emergency Core Cooling System, and isolation equipment. The 6 hour testing allowance does not significantly reduce the probability of properly monitoring post-accident parameters, when necessary, since the other channel must be OPERABLE for this allowance to be used.

L.2 CTS Table 3.3.7.5-1 Instrument 12, footnote ** requires Action 80b to be entered if one PCIV indication is inoperable in a penetration flow path with only one PCIV indication. Action 80b requires the channel to be restored to Operable status within 7 days or the unit must be shut down. ITS 3.3.3.1 ACTION A will provide 30 days to restore the inoperable channel. Furthermore, at the expiration of the 30 days, ITS 3.3.3.1 ACTION B will require a special report to be submitted per ITS 5.6.6, in lieu of requiring a unit shutdown. Due to the passive function of the instrumentation and the operator's ability to respond to an accident utilizing alternate instruments and methods for determining PCIV position, it is not appropriate to impose stringent restoration times. In addition, the piping itself is a barrier credited by the NRC to ensure leakage does not exist. This change is consistent with the BWR/6 ISTS, NUREG-1434, Rev. 1.

A.1

INSTRUMENTATION

MONITORING INSTRUMENTATION

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

LIMITING CONDITIONS FOR OPERATION

LCO 3.3.3.2

3.3.7.4 The remote shutdown system instrumentation and controls* shown in Table 3.3.7.4-1 and 3.3.7.4-2 shall be OPERABLE. LA.1

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2. A.2

ACTION: LA.1

add proposed Note 2 to ACTIONS

ACTION A- a. With the number of OPERABLE remote shutdown system instrumentation channels less than required by Table 3.3.7.4-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUT-
ACTION B- DOWN within the next 12 hours. L.1 30 LA.1

ACTION A- b. With the number of OPERABLE remote shutdown system control channels less than required by Table 3.3.7.4-2, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the
ACTION B- next 12 hours. 30 L.1

c. The provisions of Specification 3.0.4 are not applicable. L.2

NOTE 1 to ACTIONS

SURVEILLANCE REQUIREMENTS add proposed Note to Surveillance Requirements

SRs 3.3.3.2.1 & 3.3.3.2.3 4.3.7.4.1 Each of the above required remote shutdown monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.4-1 for each instrumentation channel that is normally energized. L.3 B

SR 3.3.3.2.2 4.3.7.4.2 Each of the above remote shutdown control switch(es) and control circuits shall be demonstrated OPERABLE by verifying its capability to perform its intended function(s) at least once per 18 months. LA.1

24 LD.1

* Includes transfer switches associated with remote shutdown system controls. LA.1

A.1

TABLE 4.3.7.4.1

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

LA.1

INSTRUMENT	SR 3.3.3.2.1 CHANNEL CHECK	SR 3.3.3.2.3 CALIBRATION	READOUT LOCATION
1. Service Water Pump Discharge Flow	M	R	2CES*PNL405
2. Reactor Vessel Pressure	M	R	2CES*PNL405
3. RX Vessel Water Level Wide Range	M	R	2CES*PNL405
4. RX Vessel Water Level Narrow Range	M	R	2CES*PNL405
5. RCIC Turbine Speed	R	R	2CES*PNL405
6. Suppression Pool Water Level	M	R	2CES*PNL405
7. RHR Loop "A" Flow	M	R	2CES*PNL405
8. RHR Ht. Ex. Service Water "A" Flow	M A.3	R A.5	2CES*PNL405
9. Suppression Pool Temp	M	R**	2CES*PNL405
10. RHR Loop "B" Flow	M	R	2CES*PNL405
11. RHR Ht. Ex. Service Water "B" Flow	M	R A.4	2CES*PNL405
12. Safety/Relief Valve Position (4 Valves)	R	R	2CES*PNL405
13. RCIC Flow Indicator/Controller	R	R	2CES*PNL405

L.3 LE.1

B

* CHANNEL calibration is performed per Specification 4.4.2. A.4

** CHANNEL calibration excludes sensors; sensor comparison shall be done in lieu of sensor calibration. A.5

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 This proposed change to CTS 3.3.7.4 Actions a and b provides more explicit instructions for proper application of the Actions for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," the ITS 3.3.3.2 ACTIONS Note ("Separate Condition entry is allowed for each....") and the wording for ITS 3.3.3.2 ACTION A ("one or more required Functions") provides direction consistent with the intent of the existing Actions for an inoperable remote shutdown instrumentation channel. It is intended that each function is allowed a certain time to complete the Required Actions. Since this change only provides more explicit direction of the current interpretation of the existing specifications, this change is considered administrative.

A.3 The specific Channel Checks on the RCIC Turbine Speed and RCIC Flow Indicators (CTS Table 4.3.7.4-1 Instruments 5 and 13) have been deleted since the 18 month Channel Check Surveillance Frequency is identical to the Channel Calibration Surveillance Frequency. Since the Channel Calibration completely verifies the proper functioning of the channel and encompasses a Channel Check for the two instruments, the Channel Check is not necessary and the deletion of a duplicative requirement is administrative in nature. B

A.4 Footnote * to CTS Table 4.3.7.4-1 Instrument 12, the S/RV Position, states that the 18 month Channel Calibration is performed per Specification 4.4.2. The S/RV Position instrument required by CTS Table 4.3.7.4-1 is the acoustic monitor. CTS 4.4.2 is the Surveillance Requirement for the S/RVs. Previous to Amendment 69, CTS 4.4.2 provided the setpoint (noise level) at which the acoustic monitor was required to actuate to indicate an open S/RV. Thus, the footnote was essentially a cross reference to provide the noise level setpoint to which the instrument is calibrated. Amendment 69 to the NMP2 CTS, issued by the NRC on September 11, 1995, deleted the acoustic monitoring requirements from CTS 4.4.2. It replaced the old Surveillance with a statement that there were no requirements other than those required by CTS 4.0.5. CTS 4.0.5 does not provide any requirements related to acoustic monitors. When Amendment 69 was issued, it should have also deleted the CTS

ADMINISTRATIVE

A.4 (cont'd) Table 4.3.7.4-1 footnote *. ITS 3.3.3.2 will continue to require a Channel Calibration of the S/RV acoustic monitor. Therefore, this cross reference is being deleted and is considered administrative.

A.5 The details in CTS Table 4.3.7.4-1 footnote ** related to how to perform the CHANNEL CALIBRATION of the Instrument 9 RTDs is deleted since it is duplicative of the definition of CHANNEL CALIBRATION in Chapter 1 of the ITS. This change is considered administrative since there is no change in the calibration method.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The CTS 3.3.7.4, including footnote *, CTS 3.3.7.4 Action a and b, CTS Table 3.3.7.4-1, CTS Table 3.3.7.4-2 and CTS Table 4.3.7.4-1 details relating to system design and operation (i.e., the specific instrument listings and the transfer switch requirements) are unnecessary in the LCO and are proposed to be relocated to the Technical Requirements Manual (TRM). ITS 3.3.3.2 requires the Remote Shutdown System Functions to be OPERABLE. In addition, the proposed Surveillance Requirements ensure the required transfer switches and instruments are properly tested. These requirements are adequate for ensuring each required Remote Shutdown System Function is maintained OPERABLE. The Bases also identifies that the instruments and transfer switches are required for OPERABILITY of the Remote Shutdown System and are listed in the TRM. As such, 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. The TRM will be incorporated by reference into the NMP2 USAR at ITS implementation. Changes to the relocated requirements in the TRM will be controlled by the provisions of 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LD.1 The Frequency for performing CTS 4.3.7.4.2 (proposed SR 3.3.3.2.2) has been extended from 18 months to 24 months. The SR ensures that the Remote Shutdown System transfer switches and control circuits will perform the intended function. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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. 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 small. The Remote Shutdown System is required only when the main control room is inaccessible when normal plant operating conditions exist, i.e., no transients or accidents are occurring. Also, no design basis accident (DBA) is considered for the Remote Shutdown System (including LOCA). Based on the review of the historical test data on the control switches and circuits, the need for this equipment and the impact, if any, of this change on component availability is small. 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.

LE.1 The Frequency for performing the CHANNEL CALIBRATION Surveillance of CTS 4.3.7.4.1 (proposed SR 3.3.3.2.3) for CTS Table 4.3.7.4-1 Instruments 1 through 13 has been extended from 18 months to 24 months. The SR ensures that the Remote Shutdown System Instrumentation channels indicate correctly. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) Extending the SR Frequency is acceptable because the instrumentation are designed to be highly reliable. Furthermore, the impacted Remote Shutdown System Instrumentation has been evaluated based on make, manufacturer, and model number to determine that the instrumentation's actual drift falls within acceptable allowances as determined by quantitative or qualitative analysis. The following paragraphs listed by current Remote Shutdown System Instrument Number (CTS Table 4.3.7.4-1), identify by make, manufacturer, and model number the drift evaluations performed:

Instrument 1, Service Water Pump Discharge Flow

This function is performed by Rosemount 1153DB5 transmitters, Foxboro 2AI-I3V I/E converters, Foxboro 2AP+SQE square root extractors, and GE Type 180 Indicators. The GE Type 180 indicators were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters and the Foxboro instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 2, Reactor Vessel Pressure

This function is performed by Rosemount 1153GB9 transmitters, Foxboro 2AI-I3V I/E converters, and GE Type 180 indicators. The GE Type 180 indicators were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters and the Foxboro instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of this analysis support a 24 month fuel cycle surveillance interval extension. 1 B

Instrument 3, Reactor Vessel Water Level Wide Range

This function is performed by Rosemount 1153DB5 transmitters, Foxboro 2AI-I3V I/E converters, and GE Type 180 indicators. The GE Type 180 indicators were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters and the Foxboro instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

Instrument 4, Reactor Vessel Water Narrow Range

This function is performed by Rosemount 1153DB5 transmitters, Foxboro 2AI-I3V I/E converters, and GE Type 180 indicators. The GE Type 180 indicators were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters and the Foxboro instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 5, RCIC Turbine Speed

This function is performed by a Woodward Electro-Magnetic Pick-up and a GE Type 180 indicator. The pick-up is not a calibratable device. The Woodward Pick-up and the GE Type 180 indicator were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The results of this analysis support a 24 month fuel cycle surveillance interval extension.

Instrument 6, Suppression Pool Water Level

This function is performed by Rosemount 1153DB5 transmitters, Foxboro 2AI-I3V I/E converters, and GE Type 180 indicators. The GE Type 180 indicators were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters and the Foxboro instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 7 (10), RHR Loop "A" (B) Flow

This function is performed by Rosemount 1153DB5 transmitters, Foxboro 2AI-I3V I/E converters, Foxboro 2AP+SQE square root extractors, and GE Type 180 indicators. The GE Type 180 indicators were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters and the Foxboro instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

Instrument 8 (11), RHR Heat Exchanger Service Water "A" (B) Flow

This function is performed by Rosemount 1153DB5 transmitters, Foxboro 2AI-I3V I/E converters, Foxboro 2AP+SQE square root extractors, and GE Type 180 indicators. The GE Type 180 indicators were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters and the Foxboro instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 9, Suppression Pool Temperature

This function is performed by Pyco 122-4030-04-2.7-82.3 platinum RTD (100 ohm), Foxboro 2AI-P2V ohms/E converters, and GE Type 180 indicators. The RTDs are non-calibratable devices. The Pyco RTDs and the GE Type 180 indicators were evaluated utilizing a qualitative analysis (i.e, engineering judgment). The Foxboro converters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Instrument 12, Safety/Relief Valve Position (4 Valves)

This function is performed by ENDEVCO 2273AM1 accelerometers and TEC-504A charge converters. These instruments were evaluated utilizing a qualitative analysis (i.e, engineering judgment). The results of this analysis support a 24 month fuel cycle surveillance interval extension.

Instrument 13, RCIC Flow Indicator/Controller

This function is performed by a Rosemount 1153DB5 transmitter, a Foxboro 2AI-I3V I/E converter, a Foxboro 2AP+SQE square root extractor, and a Foxboro N-250 Control Display Station. The Foxboro Control Display Station was evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount transmitters, the Foxboro converter, and the Foxboro square root extractor were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is minimal as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history, demonstrates that there are no failures that would invalidate the conclusion that the impact, if any on system availability is minimal from a change to a 24-month surveillance frequency. 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"

L.1 The allowed outage time in CTS 3.3.7.4 Actions a and b for inoperable Remote Shutdown System instrumentation and controls is extended from 7 days to 30 days in ITS 3.3.3.2 ACTION A. The Remote Shutdown System is not required to respond to any mechanistic design basis accident evaluated in the safety analysis, but is provided to comply with GDC-19 design criteria. The Specification is retained only as a significant contributor to risk reduction, and extending the allowed outage time when a Remote Shutdown System instrument channel or control/transfer switch is inoperable does not have a significant impact on that contribution.

L.2 A Note has been added to CTS 4.3.7.4.1 (ITS 3.3.3.2 Surveillance Requirements Note) to allow a channel to be inoperable for up to 6 hours solely for performance of required Surveillances. The 6 hour testing allowance has been granted by the NRC in TS amendments for Georgia Power Company's Hatch Unit 1 (amendment 185) and Unit 2 (amendment 125) and Washington Public Power Supply System's WNP-2 (amendment 149, the ITS amendment). The NRC has also granted this allowance in other topical reports for the Reactor Protection System, Emergency Core Cooling System, and isolation equipment. The 6 hour testing allowance does not significantly reduce the probability of properly monitoring Remote Shutdown System parameters, when necessary.

L.3 CTS 4.3.7.4.1 requires a Channel Check to be performed for the instruments in CTS Table 4.3.7.4-1. CTS Table 4.3.7.4-1, Instrument 12 is deenergized (does not provide proper indication) during normal operation. No specific acceptance criteria would apply to the Channel Check (since the instrument would not be indicating properly). Therefore, this Surveillance Requirement in proposed SR 3.3.3.2.1 is modified to exclude the Channel Check requirement

TECHNICAL CHANGES - LESS RESTRICTIVE

L.3 (cont'd) on this deenergized channel. This change is considered acceptable since the channels are normally deenergized and any Channel Check requirement would be essentially equivalent to no requirement. In addition, energizing this instrument channel requires operation of a transfer switch, which transfers certain ADS valve controls from the control room to the remote shutdown panel.

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) to be relocated to the Bases. This is a design detail that is not necessary to be included in the Technical Specifications to ensure the OPERABILITY of the EOC-RPT Instrumentation, since OPERABILITY requirements are adequately addressed in ITS 3.3.4.1 and proposed SR 3.3.4.1.4. Therefore, 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. 1B

LB.1 The allowed out of service time of CTS 3.3.4.2 Actions b and c.1 are extended from 12 hours to 72 hours in ITS 3.3.4.1 ACTION A. This allowed out of service time has been shown to maintain an acceptable risk in accordance with previously conducted reliability analysis (GENE-770-06-1-A, December 1992). The logic design of the instrumentation is bounded by that analyzed in the reliability analysis and the conclusions of the analysis are applicable to the NMP2 design. The results of the NRC review of this generic reliability analysis as it relates to NMP2 is documented in the NRC Safety Evaluation Report (SER) dated May 11, 1993. The SER concluded that the generic reliability analysis is applicable to NMP2, and that NMP2 meets all requirements of the NRC SER accepting the generic reliability analysis.

LD.1 The Frequencies for performing the LOGIC SYSTEM FUNCTIONAL TEST and EOC-RPT RESPONSE TIME TEST (except the breaker arc suppression time) requirements of CTS 4.3.4.2.2 and 4.3.4.2.3 (proposed SRs 3.3.4.1.3 and 3.3.4.1.5) have been extended from 18 months to 24 months to facilitate a change to the NMP2 refueling cycle from 18 months to 24 months. This SR ensures that EOC-RPT trip logic will function as designed to ensure proper response during an analyzed event. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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.

Extending the SR interval for this function is acceptable because the EOC-RPT logic is tested every 92 days by the CHANNEL FUNCTIONAL TEST (proposed SR 3.3.4.1.1). This testing of the EOC-RPT logic system ensures that a significant portion of the circuitry is operating properly and will detect

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) Furthermore, the impacted EOC-RPT instrumentation has been evaluated based on make, manufacturer and model number to determine that the instrumentation's actual drift falls within the design allowance in the associated setpoint calculation. The following paragraphs listed by CTS Trip Function, identify by make, manufacturer and model number the drift evaluation performed.

Trip Function 1, Turbine Stop Valve—Closure

This function is performed by NAMCO EA170 limit switches. Limit switches are mechanical devices that require mechanical adjustment only; drift is not applicable to these devices. Therefore, an increase in surveillance interval to accommodate a 24 month fuel cycle does not affect limit switches with respect to drift.

Trip Function 2, Turbine Control Valve—Fast Closure

This function is performed by Static-O-Ring Pressure Switches 9TA-BB5-NX-CIA-JJTTX7. The Static-O-Ring switches were evaluated by qualitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for this instrument. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is minimal as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history, demonstrates that there are no failures that would invalidate the conclusion that the impact, if any on system availability is minimal from a change to a 24-month surveillance frequency. 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"

L.1 Trip setpoints listed in CTS Table 3.3.4.2-2 and the second sentence of CTS Table 3.3.4.2-1 footnote ** are not included in the ITS and all references to these setpoints in CTS 3.3.4.2, including Action a, are deleted. The

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L.1 (cont'd) Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.4.1 reflects Allowable Values consistent with the philosophy of NUREG-1434, Rev. 1. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoints will either be in accordance with this Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, these trip setpoints are not required to be in the Technical Specifications to provide adequate protection of the public health and safety.

L.2 CTS 3.2.2 Action c essentially requires a reduction in Thermal Power to < 30% RTP if the EOC-RPT instrumentation is not restored or if the MCPR penalty is not applied. The purpose of the EOC-RPT instrumentation is to ensure a MCPR Safety Limit violation will not occur late in core life due to a turbine trip or generator load rejection. This is accomplished by tripping the normal supply breakers to the recirculation pumps, which remove the pumps from fast speed operation. Slow speed operation (energized from the low frequency motor generator) is not affected, since it is not necessary to trip the slow speed breakers to protect from a MCPR Safety Limit violation. Therefore, an additional Required Action is proposed, ITS 3.3.4.1 Required Action C.1, to allow removal of the associated recirculation pump fast speed breaker from service in lieu of reducing Thermal Power to < 30% RTP. Since this action accomplishes the functional purpose of the EOC-RPT

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is minimal as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history, demonstrates that there are no failures that would invalidate the conclusion that the impact, if any on system availability is minimal from a change to a 24-month surveillance frequency. 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"

L.1 Trip setpoints listed in CTS Table 3.3.4.1-2 are not included in the ITS and all references to these setpoints in CTS 3.3.4.1, including Action a, are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.4.2 reflects Allowable Values consistent with the philosophy of NUREG-1434, Rev. 1. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoints will either be in accordance with this Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed

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L.1 (cont'd) Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, these trip setpoints are not required to be in the Technical Specifications to provide adequate protection of the public health and safety.

L.2 CTS 3.3.4.1 Action c.2 requires the associated Trip System to be declared inoperable when two reactor vessel water level channels or two reactor vessel pressure channels in the same Trip System are inoperable. Declaring the Trip System inoperable would require restoration of the inoperable channels, as required by CTS 3.3.4.1 Action d. Placing the inoperable channels in trip is not allowed as an option. ITS 3.3.4.2 Required Action A.1 provides an option to place all inoperable channels in the tripped condition. This conservatively compensates for the inoperable status, restores the single failure capability and provides the required initiation capability of the instrumentation. Therefore, providing this option does not impact safety. However, if this action would result in system actuation, then declaring the system inoperable is the preferred action.

L.3 CTS 3.3.4.1 Action d requires that when one Trip System is inoperable, 72 hours are provided to restore the Trip System. CTS 3.3.4.1 Action e requires that when both Trip Systems are inoperable, 1 hour is provided to restore one Trip System. As described in CTS 3.3.4.1 Action c.2, a Trip System is inoperable when two channels of the same Function (i.e., reactor vessel water level or reactor vessel pressure) are inoperable in the Trip System. ITS 3.3.4.2 ACTION B addresses trip Function capability, not Trip System capability. A trip Function is maintained when sufficient channels are Operable or in trip, such that the ATWS-RPT System will generate a trip signal from the given Function on a valid signal and both recirculation pumps can be tripped. This requires two channels of the Function, in the same trip system, to each be Operable or in trip. The following is a description of the manner in which the ITS is applied, relative to the CTS.

a) When a single Trip System is inoperable under the CTS requirements, either due to two inoperable reactor vessel water level channels or two inoperable reactor vessel pressure channels, or both, the ITS will not have an inoperable Function. Therefore, ITS ACTION A would apply, which allows 14 days to restore channels. This is consistent with the CTS Action b and Action c.1 time, after the change described in Discussion of Change LB.1 above. While in this condition, the ATWS-RPT System is still capable of tripping both recirculation pumps on either Function. In addition, two similar channels inoperable is functionally equivalent to one channel inoperable (which the CTS

TECHNICAL CHANGES - LESS RESTRICTIVE

L.3 (cont'd) allows in Action b); the Trip System will not provide a trip signal from the given Function.

b) When both Trip Systems are inoperable under the CTS requirements due to two channels of the same Function being inoperable in both Trip Systems, 1 hour is allowed by CTS 3.3.4.1 Action e to restore one of the Trip Systems (by restoring the channels in the Trip System). In the ITS, when two channels of the same Function are inoperable in both trip systems, one Function will be inoperable. Therefore, ITS ACTION B would apply, which allows 72 hours to restore the inoperable channels. This is acceptable since while in this condition, the ATWS-RPT System is still capable of tripping both recirculation pumps on the other Function and operator action can still be taken to trip the recirculation pumps during this beyond design basis event. B

c) When both Trip Systems are inoperable under the CTS requirements due to two channels of one Function being inoperable in one Trip System and two channels of the other Function being inoperable in the other Trip System, the ITS will not have an inoperable Function. Therefore, ITS ACTION A would apply, which allows 14 days to restore channels. The CTS requires the channels in one Trip System to be restored within 1 hour. This is acceptable since while in this condition, the ATWS-RPT System is still capable of tripping both recirculation pumps on either Function. In addition, when one channel is inoperable, the associated Function (either Drywell Pressure — High or Reactor Vessel Water Level — Low Low, Level 2) cannot actuate the Trip System, since both channels of a Function must trip to actuate the Trip System (i.e., each Trip System is a two-out-of-two logic for each Function). This condition is covered by CTS 3.3.4.1 Action b. When two channels of the same Function are inoperable in a Trip System, this condition is functionally equivalent to that covered by CTS 3.3.4.1 Action b (i.e., one channel inoperable). That is, with both channels of the same Function inoperable in a Trip System, the associated Function cannot actuate the Trip System, identical to the results when one channel is inoperable in a Trip System. B

d) When both Trip Systems are inoperable under the CTS requirements due to all channels of both Functions inoperable in both Trip Systems, the ITS will have two inoperable Functions. Therefore, ITS ACTION C would apply, which allows 1 hour to restore channels. This is consistent with the CTS Action e time.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.4 CTS 3.3.4.1 Actions d and e require the unit to be placed in Startup (Mode 2) within 6 hours if the ATWS-RPT instrumentation is not restored within the allowed out-of-service times. The purpose of the ATWS-RPT instrumentation is to trip the recirculation pumps. Therefore, an additional Required Action is proposed, ITS 3.3.4.2 Required Action D.1, to allow removal of the associated recirculation pump breaker(s) from service in lieu of being in MODE 2 within 6 hours. Since this action accomplishes the functional purpose of the ATWS-RPT instrumentation and enables continued operation in a previously approved condition, this change does not have a significant effect on safe operation.

A.1

Specification 3.3.5.1

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

M.2 add proposed Required Actions C.1 and E.1

ACTION 32 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, within 24 hours declare the associated ADS Trip System or ECCS inoperable.

ACTIONS C, F and G. A.7 L.2 ACTION H

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within 24 hours.

ACTION B

ACTION 34 - Not Used.

L.7

ACTION 35 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 24 hours or declare the associated ADS valve or ECCS inoperable. L.12 B

ACTIONC ACTION H

ACTION 36 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement: M.2

ACTION B

a. With one channel inoperable, add proposed Required Action B.2 place the inoperable channel in the tripped condition within 24 hours* or declare the HPCS system inoperable. L.5

ACTION H

b. With more than one channel inoperable, add proposed Required Actions B.1 and B.3.1 declare the HPCS system inoperable. M.2

ACTION B ACTION H

ACTION 37 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, add proposed Required Action D.1 place at least one inoperable channel in the tripped condition within 24 hours* or declare the HPCS system inoperable. A.9 add proposed Required Action D.2.2

ACTION D ACTION H

ACTION 38 - With the number of OPERABLE channels less than the Total Number of Channels, declare the associated emergency diesel generator inoperable and take the ACTION required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

ACTION 39 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel in the tripped condition within 1 hour*; operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

A.6 moved to LCO 3.3.8.1

* The provisions of Specification 3.0.4 are not applicable. A.8

ADMINISTRATIVE

A.5 (cont'd) A.2.g and B.2.f (ITS Table 3.3.5.1-1 Functions 4.f and 5.g). Since the change involves no design change but is only a difference in nomenclature, this change is considered administrative.

A.6 The technical content of the requirements of CTS Tables 3.3.3-1, 3.3.3-2, and 4.3.3.1-1, Trip Functions D and E, including CTS Table 3.3.3-1 Actions 38 and 39, CTS Table 3.3.3-2 footnote **, and CTS Table 4.3.3.1-1 footnote †, are being moved to ITS 3.3.8.1, "Loss of Power Instrumentation," in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. Any technical changes to these requirements are addressed in the Discussion of Changes for ITS: 3.3.8.1, in this Section.

A.7 CTS Table 3.3.3-1 Actions 30 and 32 require declaring the associated system or ADS Trip System inoperable when the time to restore the channel (24 hours) has expired. When the restoration time provided in these Actions have expired for the ADS Functions, the associated ADS Trip System is declared inoperable, and the action provided in CTS 3.3.3 Action c is taken, since this Action provides the required actions when an ADS Trip System is inoperable. Action c provides 72 hours or 7 days to restore the ADS Trip System, depending upon whether or not both RCIC and HPCS systems are Operable, and when the restoration time expires, a shutdown is required. In ITS 3.3.5.1 ACTIONS F and G, the requirement to declare the associated system (i.e., ADS trip system) inoperable has been deleted. In its place, the total time to restore the channel has been provided. These four CTS Actions have essentially been combined into two proposed ACTIONS, depending upon whether or not the channel is allowed to be tripped (ITS 3.3.5.1 ACTIONS F and G, respectively). Since the total time to restore the channel/trip system has not changed, except as discussed in Discussion of Change L.5 below, this change is considered administrative. B

A.8 The allowance in the CTS 3.3.2 Action and CTS Table 3.3.3-1 Actions 30.g, 36.a, and 37 footnote *, which states the provisions of Specification 3.0.4 are not applicable has been deleted since proposed LCO 3.0.4 provides this allowance (i.e., the allowance has been moved to LCO 3.0.4). Therefore, deletion of this allowance is administrative.

A.9 CTS Table 3.3.3-1 Action 37 requires placing the inoperable channel in trip when a HPCS Pump Suction Pressure—Low (Transfer) or a HPCS Suppression Pool Water Level—High channel is inoperable. A new Required Action has been added, ITS 3.3.5.1 Required Action D.2.2, to allow the HPCS pump suction to be aligned to the suppression pool in lieu of tripping the channel, if a Pump Suction Pressure—Low or Suppression Pool Water Level—High channel

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 Trip setpoints listed in CTS Tables 3.3.2-2 and 3.3.3-2 are not included in the ITS and all references to these setpoints in CTS 3.3.3 are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.5.1 reflects Allowable Values consistent with the philosophy of NUREG-1434, Rev. 1. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoints will either be in accordance with this Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, these trip setpoints are not required to be in the Technical Specifications to provide adequate protection of the public health and safety. 1B

L.2 CTS 3.3.3 Action c requires restoration of an ADS Trip System to Operable status when it is inoperable; it does not allow placing the inoperable channels in trip and continuing to operate. CTS Table 3.3.3-1 Action 32 requires an inoperable ADS Reactor Vessel Water Level - Low, Level 3 (Permissive) channel (Trip Functions A.2.c and B.2.c) to be restored to Operable status; it does not allow placing the inoperable channel in trip and continuing to operate. An option is provided in ITS 3.3.5.1 Required Action F.2 to place all

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) inoperable channels in the tripped condition. This conservatively compensates for the inoperable status, restores the single failure capability, and provides the required initiation capability of the instrumentation. Therefore, providing this option does not impact safety. However, if this action would result in system actuation, then declaring the system inoperable is the preferred action.

L.3 The pressure at which ADS is required to be OPERABLE, as specified in CTS Table 3.3.3-1 footnote (c), CTS Table 4.3.3.1-1 footnote **, and CTS 3.3.3 Action c, is increased from 100 psig to 150 psig in ITS 3.3.5.1 to provide consistency of the OPERABILITY requirements for all ECCS and RCIC equipment. Small break loss of coolant accidents at low pressures (i.e., between 100 psig and 150 psig) are bounded by analysis performed at higher pressures. The ADS is required to operate to lower the pressure sufficiently so that the low pressure coolant injection (LPCI) and low pressure core spray (LPCS) systems can provide makeup to mitigate such accidents. Since these systems can begin to inject water into the reactor pressure vessel at pressures well above 150 psig (225 psid, steam dome pressure to drywell pressure, and steam dome pressure <225 psig for LPCI; 289 psid, steam dome pressure to drywell pressure, and steam dome pressure <305 psig for LPCS), there is no safety significance in the ADS not being OPERABLE between 100 psig and 150 psig.

L.4 CTS Tables 3.3.3-1 and 4.3.3.1-1 (including footnote *) require Trip Functions C.1.d (Pump Suction Pressure - Low (Transfer)) and C.1.e (Suppression Pool Water Level - High) to be Operable in Modes 1, 2, and 3, and in Modes 4 and 5 when the HPCS System is required to be Operable per Specification 3.5.2 and 3.5.3. The requirements for automatic restoration of the HPCS water source to the suppression pool are dependent on the availability of sources and the need to realign. With the HPCS pre-aligned to the suppression pool, there is no need to require automatic realignment. When shutdown (Modes 4 and 5), an OPERABLE CST can provide sufficient water to adequately minimize the consequences of a vessel draindown event and automatic realignment to the Suppression Pool is unnecessary. In addition, the Suppression Pool Water Level - High Function is provided to ensure that the suppression pool design values are not exceeded should there be a blowdown of the reactor vessel pressure through the S/RVs. Since the reactor is depressurized in Modes 4 and 5, a blowdown cannot occur and this automatic transfer feature is not necessary. Only with insufficient water in the CST is automatic realignment to the Suppression Pool necessary in the shutdown Modes. Therefore, ITS Table 3.3.5.1-1 Function 3.d (Pump Suction Pressure—Low) is only required to be Operable in Modes 4 and 5 when HPCS is Operable for compliance with LCO 3.5.2 and aligned to the CST while CST water level is not within the

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd) limit of SR 3.5.2.2 (as described in footnote (c)), and ITS Table 3.3.5.1-1 Function 3.f (Suppression Pool Water Level—High) is not required to be Operable in Modes 4 and 5.

L.5 CTS Table 3.3.3-1 Actions 30.b and 36.b require the associated ECCS to be declared inoperable immediately when more than one channel of a Trip Function is inoperable. These Actions apply to the following CTS Table 3.3.3-1 Trip Functions: LPCS, LPCI, and ADS Reactor Vessel Water Level - Low, Low, Low, Level 1 (Trip Functions A.1.a, A.2.a, B.1.a, and B.2.a), HPCS Reactor Vessel Water Level - Low, Low, Level 2 (Trip Function C.1.a), LPCS, LPCI, and HPCS Drywell Pressure - High (Trip Functions A.1.b, B.1.b, and C.1.b). ITS 3.3.5.1 ACTION B will allow 24 hours and ITS 3.3.5.1 ACTION F will allow 96 hours or 8 days (depending upon whether HPCS and RCIC Systems are both Operable) to place inoperable channels in trip when two channels of a Function are inoperable, prior to declaring the associated ECCS inoperable, provided ECCS initiation capability is maintained. B

The channels for each of the individual LPCS, LPCI, and ADS Functions are combined in a two-out-of-two logic; thus when one or both channels of an individual Trip Function are inoperable, the individual Trip Function will not perform its intended function. When one of the two channels are inoperable and the associated Function cannot perform its intended function, CTS Table 3.3.3-1 Action 30.a currently allows 24 hours to trip a channel (i.e., loss of the Trip Function is currently allowed for 24 hours). B

The channels for the HPCS Functions are combined in a one-out-of-two-taken-twice logic; thus if one channel in each trip system of a Function is inoperable, the Function can still perform its intended function. This condition is analogous to the Functions described above, since Action 36.a allows 24 hours to trip the inoperable channel when only one channel is inoperable. B

The 24 hour, 96 hour, and 8 day out of service time was evaluated and approved for use at NMP2 by the NRC in the Safety Evaluation Report dated May 11, 1993. Therefore, allowing two channels of a LPCS, LPCI, and ADS Function to be inoperable is equivalent to one channel inoperable; in both cases, the Function cannot perform its intended function. Allowing two HPCS channels (one per trip system) of a Function to be inoperable is acceptable since the Function can still perform its intended function. However, this 24 hour, 96 hour, or 8 day time (provided in ITS 3.3.5.1 Required Actions B.3.1 and F.2) will only be allowed if the redundant ECCS (in the case of LPCS and LPCI) or trip system (in the case of ADS and HPCS) is maintaining initiation capability (ITS 3.3.5.1 Required Actions B.1, B.2, and F.1). This will ensure the overall ECCS function is maintained during the associated time period. In addition, B B B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.5 (cont'd) allowing all channels to be tripped in lieu of restoring the channels conservatively compensates for the inoperable status, restores the single failure capability, and provides the required initiation capability of the instrumentation. Therefore, providing this option does not impact safety. However, if this action would result in system actuation, then declaring the system inoperable is the preferred action.

L.6 CTS Table 3.3.2-1 Action 20, which requires a unit shutdown, is required to be taken when a Reactor Vessel Water Level — Low, Level 3 or a Drywell Pressure — High channel is not placed in trip as required by CTS 3.3.2 Actions b and c. These Functions actuate the Group 4 valves, which are not PCIVs, as well as certain PCIVs covered by ITS 3.3.6.1 (ITS 3.3.6.1 will control the instrument requirements for the PCIVs). The Group 4 valves are valves that need to go closed to ensure the LPCI A and B flow is not diverted from injecting into the core. They are the RHR B discharge to radwaste valves and the RHR A and B heat exchanger sample valves. ITS 3.3.5.1 Required Action B.3.2 has been added to allow isolation of the affected LPCI flow diversion flow path(s) in lieu of a unit shutdown. Isolation of the affected flow diversion flow path(s) performs the safety function of the instruments. Operation should be allowed to continue since isolation of the flow diversion flow path(s) also does not render the associated LPCI subsystem inoperable; it actually maintains the associated LPCI subsystem Operable. The Completion Time to isolate the flow path(s) will be the same as the Completion Time currently provided to trip the inoperable channel. In addition, if the affected flow path(s) are not isolated, ITS 3.3.5.1 ACTION H will require the associated LPCI subsystem to be declared inoperable immediately. Allowing the flow diversion flow path(s) to remain unisolated if an inoperable channel is not tripped will only affect one LPCI subsystem. The NRC has previously approved in CTS 3.5.1 (as well as guidance provided in the memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," dated December 1, 1975) an allowance for one LPCI subsystem to be inoperable (e.g., when the LPCI flow rate does not meet the flow rate assumed in the accident analysis) for up to 7 days. In addition, extending the shutdown time from immediately to 7 days (the Completion Time for one inoperable LPCI subsystem) avoids an unnecessary plant shutdown when remaining ECCS subsystems are capable of providing adequate flow to meet analysis assumptions. Therefore, this change is considered acceptable. This allowance is also consistent with CTS 3.3.3 ACTIONS which require declaring the associated ECCS subsystem inoperable when an actuation channel is inoperable and not tripped or restored (e.g., as in the case when a Drywell Pressure — High channel, which initiates the associated ECCS subsystem, is inoperable and untripped).

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.7 The completion time to restore the manual initiation function for all ECCS functions has been increased from 8 hours in CTS Table 3.3.3-1 Action 35 to 24 hours in ITS 3.3.5.1 Required Action C.2. This change is acceptable since the manual initiation functions are not assumed in any accident or transient analysis. This change is in accordance with Topical Report NEDC-30936-P-A, December 1988, and the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. The results of the NRC review of this generic reliability analysis as it relates to NMP2 is documented in the NRC Safety Evaluation Report (SER) dated May 11, 1993. The SER concluded that the generic reliability analysis is applicable to NMP2 and that NMP2 meets all requirements of the NRC SER accepting the generic reliability analysis.

L.8 The CHANNEL FUNCTIONAL TEST of all Manual Initiation Functions in CTS Table 4.3.3.1-1 footnote (a) is performed at least once per 18 months during shutdown. The proposed LOGIC SYSTEM FUNCTIONAL TEST (proposed SR 3.3.5.1.6) for these Functions (see Discussion of Change A.10 above for changes to this test) does not include this restriction on plant conditions that requires the Surveillance to be performed while shutdown. These Surveillances can be performed while operating without jeopardizing safe plant operations. The control of plant conditions appropriate to perform the test is an issue for procedures and scheduling and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction. As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specifications Surveillances that do not dictate plant conditions for the Surveillance.

L.9 CTS Table 3.3.2-1 requires Trip Function 1.a.3, Reactor Vessel Water Level — Low, Level 3, Trip Function 1.b, Drywell Pressure — High, to close the Group 4 valves. CTS Table 3.3.2-4 specifies that Group 4 valves are the RHR Sample and Radioactive Waste valves. There are only two in-series radwaste valves and these are in the RHR B subsystem. There are four RHR sample valves, two in-series valves for both RHR A and RHR B subsystems. As described in Discussion of Change A.11 above, these valves are not PCIVs, but are needed to close in order to ensure LPCI A and B flow is not diverted from injecting into the core. However, only one of the two in-series valves in each flow path needs to close to isolate the flow path and preclude flow diversion from the associated LPCI subsystem. In addition, only one of the two valves in each flow path receives all signals and motive power from its own divisionalized power source. That is, one of the two valves in the RHR A flow path (a Division 1 subsystem) receives power and logic to close the valve from Division 2, even though the RHR A pump and LPCI injection valves are powered from Division 1. Conversely, one of the two valves in each RHR B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.9 (cont'd) flow path (a Division 2 subsystem) receives power and logic to close the valves from Division 1. The valves only need to be closed if the associated LPCI subsystem is initiated, and with no power to the RHR pump or LCPI injection valves, there is no reason to close the valve receiving power and logic from the other division. In addition, there are other LPCI flow diversion pathways that are much larger (hence would divert much more flow) that have only one valve that automatically closes on an ECCS initiation signal (e.g., suppression pool cooling/test valve). Therefore, the ITS will only require one valve in each flow path to be Operable, and the valve will be the associated divisionalized valve. This is identified in the Bases since the valve descriptions have been relocated to the Bases (see Discussion of Change LA.2 above). This is acceptable since, if a required valve fails to close on an initiation signal, the remaining LPCI subsystems will continue to provide adequate flow to meet the analysis assumptions.

L.10 CTS Table 3.3.2-1 requires Trip Function 1.m, Manual Isolation Pushbutton, to be Operable for the Group 4 valves. This Trip Function, along with all references to it in CTS 3/4.3.2, will not be included in the ITS to close the Group 4 valves. The Group 4 valves are not PCIVs, but they are valves that need to go closed to ensure the LPCI A and B flow is not diverted from injecting into the core. They are the RHR B discharge to radwaste valves and the RHR A and B heat exchanger sample valves. These valves are not routinely opened during power operation of the unit; they are normally used only in MODES 3, 4, and 5. When they are opened, a remote control switch, located on a front panel in the control room, is used and a plant operator normally remains in the vicinity of the valve control switch during its use. In addition, the Manual Isolation Pushbutton Function is not assumed in any accident or transient analysis. The ECCS is assumed to actuate automatically. Also, the Manual Isolation Pushbutton Function not only closes the Group 4 valves, but also closes the main steam line isolation valves, and other automatic PCIVs; thus the Function will be maintained Operable to close these PCIVs in ITS 3.3.6.1 (ITS Table 3.3.6.1 Functions 1.h, 2.d, 3.m, 4.h, and 5.f).

L.11 This change revises the Technical Specification setpoints for CTS Table 3.3.3-2 Trip Functions A.1.j, B.1.h, and C.1.f (ITS Table 3.3.5-1, Functions 1.l, 2.j, and 3.h) to reflect Allowable Values consistent with the philosophy of NUREG-1434. (While the addition of an upper Allowable Value for the three Functions appears more restrictive, the new upper Allowable Value is lower than the Allowable Value currently in the CTS.) These Allowable Values (to be included in Technical Specifications) have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1,

TECHNICAL CHANGES - LESS RESTRICTIVE

L.11 (cont'd) dated 11/6/95. The Allowable Value selection evaluation used actual NMP2 operating and surveillance trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The proposed Allowable Values have been established from each design or safety analysis limit by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

L.12 CTS Table 3.3.3-1 Action 35 requires declaring the associated ADS valve inoperable when the time to restore the inoperable ADS manual initiation channel (8 hours) has expired (The 8 hour restoration time has also been changed in the ITS to 24 hours as described in DOC L.7 above). Each ADS manual initiation channel affects all the ADS valves, thus Action 35 effectively requires all ADS valves to be declared inoperable. With all ADS valves inoperable, CTS 3.5.1 Action e.2 requires a unit shutdown. In lieu of requiring a unit shutdown, ITS 3.3.5.1 ACTION G will allow an additional 72 hours or 7 days to restore the channel, depending upon whether or not both HPCS and RCIC Systems are Operable. At the expiration of this extended time, a unit shutdown will be required if the channel is not restored to Operable status. This additional restoration time is consistent with the current restoration time currently approved by the NRC (in CTS 3.3.3 Action c) when other required ADS automatic channels are inoperable. This change is considered acceptable since the ADS Manual Initiation Function is not assumed in any accident or transient analysis. B

A.1

Specification 3.3.5.2

TABLE 3.3.5-1 (Continued)

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

ACTION 50 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement:

ACTION B

M.2

add proposed Required Action B.1

a. For one Trip System, place the inoperable channel(s) ~~and/or that Trip System~~ in the tripped condition within 24 hours or declare the RCIC system inoperable.

A.7 B

ACTION E

b. For both Trip Systems with more than one channel inoperable, ~~declare the RCIC system inoperable.~~

ACTIONS B and E

L.2

ACTION 51 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place at least one inoperable channel in the tripped condition within 24 hours, or declare the RCIC system inoperable.

ACTION D

ACTION E

add proposed Required Action D.1

M.2

ACTION 52 - With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the inoperable channel to OPERABLE status within 24 hours or declare the RCIC system inoperable.

ACTION C

ACTION E

add proposed Required Action D.2.2

A.5

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ADMINISTRATIVE

A.5 (cont'd) this proposed action results in the same condition as if a channel were tripped (tripping one channel results in the suction being aligned to the suppression pool), this change is considered administrative.

A.6 CTS Table 4.3.5.1-1 requires a CHANNEL FUNCTIONAL TEST (CFT) of Functional Unit 4, the Manual Initiation Function, every 92 days. Footnote † modifies this requirement such that the Manual Initiation switches are required to be tested every 18 months, while the remaining circuitry associated with the Manual Initiation Function is required to receive a CFT every 92 days as part of the circuitry required to be tested for automatic system actuation. The automatic logic circuitry that is common with the manual logic circuitry is not tested every 92 days. The automatic logic is a one-out-of-two taken twice logic, thus when a CFT is performed on the automatic initiation channels, the logic that is common to the manual logic is not required to be tested (the channel loses identity prior to the initiating the logic parts that are common). Therefore, the 92 day CFT does not actually require any testing of the Manual Initiation logic. The logic is tested completely when the switches are tested; every 18 months. CTS 4.3.5.2 and proposed SR 3.3.5.2.5 require a Logic System Functional Test (LSFT) every 18 months (changed to 24 months - see Discussion of Change LD.1 below). Since the LSFT is a complete test of the logic, including the Manual Initiation switches, there is no need to require a CFT. Therefore, ITS 3.3.5.2 only requires an LSFT, and this change is considered administrative.

A.7 CTS Table 3.3.5-1 Action 50.a requires the inoperable channel and/or the associated Trip System to be placed in trip when a channel is inoperable. ITS 3.3.5.2 ACTION B does not include the allowances to place the trip system in trip; only the inoperable channel is allowed to be tripped. For the RCIC Instrumentation, there is no manual pushbutton or switch to place only the associated trip system in trip. This design is similar to that for the ECCS Systems. Therefore, the manner in which NMP2 currently complies with CTS Table 3.3.5-1 Action 50.a is to place the inoperable channel in trip. Thus, deletion of this allowance is considered administrative. B

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 CTS Table 3.3.5-1 Note (d) and Table 4.3.5.1-1 footnote ** have been deleted. The allowance in the notes specifies that the Manual Initiation Function is not required to be OPERABLE with the indicated reactor water level on the wide range instruments greater than the Level 8 setpoint coincident with the reactor pressure less than 600 psig because of hot calibration/cold operation level error. With water level greater than the Level 8 setpoint, the RCIC steam admission valve will receive a close signal and in turn the RCIC injection valve will remain closed due to a position interlock with the RCIC steam admission valve position signal. An initiation signal (manual or low water level) in this condition will not start the RCIC system since the High Water Level 8 actuation overrides the initiation signal. If a LOCA were to occur in this situation or if another reactor level transient were to occur, the reactor water level will decrease, the High Water Level 8 will clear, and the automatic actuation at Level 2 will function as designed. In addition, if operations decided to initiate the system manually, it may be performed when the High Water Level 8 has cleared. Since the Manual Initiation Function remains OPERABLE under these conditions, the notes have been deleted. This deletion is considered more restrictive on plant operation.

M.2 Appropriate Required Actions have been added (in ITS 3.3.5.2 Required Actions B.1 and D.1) to Actions 50 and 51 of CTS Table 3.3.5-1 for response to loss of RCIC initiation capability of a Function. These additional requirements provide clear direction of the necessary Actions when in this condition. The Required Actions will only allow continued operations for 1 hour if a loss of RCIC initiation capability of a Function occurs. This change represents an additional restriction on plant operation necessary to ensure the risk associated with plant operation in this condition is minimized.

M.3 An additional Function has been added, ITS Table 3.3.5.2-1 Function 4, to provide requirements for the RCIC Pump Suction Pressure — Timer. The Pump Suction Pressure — Low Function (CTS Table 3.3.5-1 Functional Unit 3, ITS Table 3.3.5.2-1 Function 3) is time delayed to preclude spurious automatic suction source swaps. To ensure proper operation of the logic, the time delay relay must function. Appropriate ACTIONS and Surveillances have also been added. This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The detail in CTS 4.3.5.2 relating to methods (simulated automatic operation) for performing the LOGIC SYSTEM FUNCTIONAL TESTS are proposed to be relocated to the Bases. This detail is not necessary to ensure the OPERABILITY of the RCIC System Instrumentation. The requirements of ITS 3.3.5.2 and proposed SR 3.3.5.2.5 are adequate to ensure the RCIC System instruments are maintained OPERABLE. Therefore, 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.

LA.2 System design and operation details specified in CTS Table 3.3.5-1, Note (c) and (e) (which describe the number of trip systems and the logic design for the Manual Initiation and Pump Suction Pressure—Low (Transfer) Functional Units) are proposed to be relocated to the Bases. Details relating to system design and operation are unnecessary in the LCO. These details are not necessary to ensure the OPERABILITY of the RCIC System Instrumentation. The requirements of ITS 3.3.5.2 and the associated Surveillance Requirements are adequate to ensure the RCIC System instruments are maintained OPERABLE. Therefore, 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.

LB.1 CTS Table 3.3.5-1 footnote (a), which allows a delay in entering the associated Action statement, has been clarified to allow current Functional Unit 4 (ITS Table 3.3.5.2-1 Function 5), the Manual Initiation Function, to be inoperable and delay entering the associated ACTIONS for 6 hours, regardless of the remaining RCIC initiation capability of the Manual Initiation Function. For this Function, loss of one channel results in a loss of RCIC initiation capability. This condition was evaluated in the reliability analysis of GENE-770-06-2-A, December 1992, and found to be acceptable. This analysis is the basis for the current 6 hour allowance in the Note. The results of the NRC review of this generic reliability analysis as it relates to NMP2 is documented in NRC Safety Evaluation Report (SER) dated May 11, 1993. The SER concluded that the generic reliability analysis is applicable to NMP2 and that NMP2 meets all requirements of the NRC SER accepting the generic reliability analysis.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST (LSFT) of CTS 4.3.5.2 and the CHANNEL FUNCTIONAL TEST for the RCIC Manual Initiation Function specified in CTS Table 4.3.5.1-1 Functional Unit 4 Note † (changed to LSFT in Discussion Change A.6 above) has been extended from 18 months to 24 months in proposed SR 3.3.5.2.5 to facilitate a change to the NMP2 refueling cycle from 18 months to 24 months. This SR ensures that RCIC logic will function as designed to ensure proper response during an analyzed event. 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 4.0.2 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 4.0.2 and proposed SR 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. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance 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 small. The system function testing performed in ITS 3.5.3 overlaps this surveillance to provide complete testing of the safety function. The RCIC system is tested on a more frequent basis during the operating cycle in accordance with proposed SRs 3.3.5.2.1, 3.3.5.2.2, and 3.3.5.2.3. This testing of the RCIC system ensures that a significant portion of the RCIC circuitry is operating properly and will detect significant failures of this circuitry. RCIC system actuating logic is designed to be single failure proof and therefore, is highly reliable.

Based on the above discussion, the impact, if any, of this change on system availability is small. The review of historical surveillance data also demonstrated that there are no failures that would invalidate this conclusion. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

LE.1 The Frequencies for performing the CHANNEL CALIBRATIONS of CTS 4.3.5.1 and CTS Table 4.3.5.1-1 for Functional Units 1, 2, and 3 have been extended from 18 months to 24 months in proposed SR 3.3.5.2.4. The proposed change will allow these Surveillances to extend their 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 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) (i.e., a maximum of 30 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 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.

Extending the SR Frequency is acceptable because the RCIC initiation logic is designed to be single failure proof and therefore is highly reliable. Furthermore, the impacted RCIC instrumentation has been evaluated based on make, manufacturer and model number to determine that the instrumentation's actual drift falls within the design allowance in the associated setpoint calculation. The following paragraphs listed by CTS Table 4.3.5.1-1 Functional Unit number, identify by make, manufacturer and model number the drift evaluations performed:

Functional Unit 1, Reactor Vessel Water Level—Low Low, Level 2

This function is performed by Rosemount 1153DB5 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Functional Unit 2, Reactor Vessel Water Level—High, Level 8

This function is performed by Rosemount 1153DB5 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) **Functional Unit 3**, Pump Suction Pressure—Low (Transfer)

This function is performed by Rosemount 1153DB4 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is small as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history demonstrates that there are no failures that would invalidate the conclusion that the impact, if any, on system availability is small from a change to a 24-month surveillance frequency. 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"

L.1 Trip setpoints listed in CTS Table 3.3.5-2 are not included in the ITS and all references to these setpoints in CTS 3.3.5 are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.5.2 reflects Allowable Values consistent with the philosophy of NUREG-1434, Rev. 1. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A; limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoints will either be in accordance with this Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required to be in the Technical Specifications to provide adequate protection of the public health and safety.

L.2 An option is added to CTS Table 3.3.5-1 Action 50.b for when one or more inoperable channels exist. This option (in ITS 3.3.5.2 Required Action B.2) is to place all inoperable channels in the tripped condition. This conservatively compensates for the inoperable status, restores the single failure capability with regard to system actuation, and provides the required initiation capability of the instrumentation. Therefore, providing this option does not impact safety. However, if this action would result in system actuation, then declaring the system inoperable is the preferred action.

L.3 The CHANNEL FUNCTIONAL TEST of the RCIC Manual Initiation Function of CTS Table 4.3.5.1-1 footnote † is performed at least once per 18 months during shutdown. The proposed LOGIC SYSTEM FUNCTIONAL TEST (proposed SR 3.3.5.2.5) for this Function (see Discussion of Change A.6 above for changes to this test) does not include this restriction on plant conditions that requires the Surveillance to be performed while shutdown. This Surveillance can be performed while operating without jeopardizing safe plant operations. The control of plant conditions appropriate to perform the test is an issue for procedures and scheduling and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction. As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specifications Surveillances that do not dictate plant conditions for the Surveillance.

Table 3.3.6.1-1

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL(a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM(b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. Primary Containment Isolation Signals				
a. Reactor Vessel Water Level				
1. Low, Low, Low, Level 1	1	2	1, 2, 3	20 D
2. Low, Low, Level 2 (c)(d)	2,3,6,7,8,9	2	1, 2, 3 and *	20 H (group 2,3,8,9)/F (group 6,7)
3. Low, Level 3	4,5	2	1, 2, 3	20 J (group 5)
b. Drywell Pressure - High (c)(d)	3,4,8,9	2	1, 2, 3	20 H
c. Main Steam Line				
1. Radiation - High(e)	1,2	2	1, 2, 3	21
2. Pressure - Low	1	2	1	23 E
3. Flow - High	1	2/Line	1, 2, 3	21 D
d. Main Steam Line Tunnel				
1. Temperature - High	1	2	1, 2, 3	21 D
2. ΔTemperature - High	1	2	1, 2, 3	21 D
3. Temperature - High MSL Lead Enclosure	1	6 2 per area	1, 2, 3 Note(c)	21 D
e. Condenser Vacuum-Low	1	2	1, 2**, 3**	21 D
f. RHR Equipment Area Temperature - High (HXs/A&B Pump Rooms)	5,10	2 1 per area	1, 2, 3 (for group 5 only)	28 F
g. Reactor Vessel Pressure - High (RHR Cut-in Permissive)	5	2	1, 2, 3	28 F

Table 3.3.6.1-1

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

Function TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
1,2,3,4,5 1. Primary Containment Isolation Signals (Continued) (A.6)				
2c h. SGTS Exhaust - High Radiation	9	1	1, 2, 3	27 F (L.7)
i. RWCU System				
4.a 1) ΔFlow - High	6, 7	1	1, 2, 3	22 F
4.b 2) ΔFlow - High, Timer	6, 7	1	1, 2, 3	22 F
4.g 3) Standby Liquid Control, SLCS, Initiation	6(f), 7(f)	1	1, 2	22 I
j. RWCU Equipment Area				
4.d 1) Pump Room A Temperature - High	6, 7	1 (1 per room)	1, 2, 3	22 F
4.d 2) Pump Room B Temperature - High	6, 7	1	1, 2, 3	22 F
4.c 3) HX Room Temperature - High	6, 7	1 (A.16)	1, 2, 3	22 F
k. Reactor Building Pipe Chase				
3.h, 4.e, 5.d 1) Azimuth 180° (Upper), Temperature - High (A.16)	5, 6, 7, 10	1 (1 per area, A.16)	1, 2, 3 (L.5 for Group 5 only)	22 F
3.h, 4.e, 5.d 2) Azimuth 180° (Lower), Temperature - High	5, 6, 7, 10	1	1, 2, 3	22 F
3.h, 4.e, 5.d 3) Azimuth 40°, Temperature - High	5, 6, 7, 10	1	1, 2, 3	22 F
3.i, 5.e l. Reactor Building Temperature - High	5, 10	1 (A.8)	1, 2, 3	22 F
1.h, 2.d, 4.h, 5.f m. Manual Isolation Pushbutton (NSSSS)	1	2	1, 2, 3	25
	2, 4, 5	2	1, 2, 3	26
	3, 6, 7	1	1, 2, 3	26
	8	2	1, 2, 3	25, 27
	9	1	1, 2, 3	27

A.7 moved to LCO 3.3.5.1

4 → 11.2

A.1

Specification 3.3.6.1

add proposed ACTION G

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A.1

Specification 3.3.6.1

Table 3.3.6.1-1

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

add proposed Required Action D.1 (L.2)

add proposed ACTION F (L.3)

add proposed ACTION J (L.4 for MODES 1, 2, and 3; A.1 for MODES 4 and 5)

ACTION

ACTIONS D and H ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours. (L.8)

ACTION D ACTION 21 - ~~Be in at least STARTUP~~ with the associated isolation valves closed within ~~6~~ 12 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

add proposed Required Action I.1 (L.14 / B)

ACTIONS F and I ACTION 22 - Close the affected system isolation valves within 1 hour ~~and declare the affected system inoperable.~~ (A.10)

ACTION E ACTION 23 - Be in at least STARTUP within 6 hours.

ACTION 24 - Not used. (L.9)

Isolate the affected penetration

ACTION G ACTION 25 - ~~Restore the manual isolation function to OPERABLE status~~ within ~~8~~ 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION H

ACTION 26 - ~~Restore the manual isolation function to OPERABLE status within 8 hours~~ or close the affected system isolation valves within the ~~next~~ 24 hour ~~and declare the affected system inoperable.~~ (L.10) (A.10)

ACTION G

ACTION H

ACTION 27 - Establish REACTOR BUILDING INTEGRITY with the standby gas treatment system operating within 1 hour (L.11)

add proposed ACTION G (L.7)

ACTION F ACTION 28 - ~~Lock~~ the affected system isolation valves closed within 1 hour ~~and declare the affected system inoperable.~~

A.10

L.11

A.7 also moved to LCO 3.3.6.2 (for Secondary Containment Isolation Functions)

ADMINISTRATIVE

A.7 (cont'd) OPERABILITY, the instruments will be moved to ITS 3.3.5.1, ECCS Instrumentation. Any technical changes to these requirements are addressed in the Discussion of Changes for ITS 3.3.5.1.

A.8 Each of the current Isolation Instrumentation Manual Initiation switch and push button channels in CTS Table 3.3.2-1 Trip Function 1.m actually provides two inputs to the isolation logic; one input actuated by rotating a collar switch and a second input by depressing the inner push button. Therefore, using the ITS format that each input is considered a channel, the minimum channels is more appropriately specified as "4" in ITS Table 3.3.6.1-1 Functions 1.h, 2.d, 4.h, and 5.f. Since the change involves no design change but is only a difference in nomenclature, this change is considered administrative.

A.9 Not used. 1 B

A.10 An action to "declare the affected system inoperable," as presented in CTS Table 3.3.2-1 Actions 22, 26, and 28, is an unnecessary reminder that other Technical Specifications may be affected. This is essentially a "cross reference" between Technical Specifications that has been determined to be adequately provided through training. In addition, the definition of "OPERABILITY in ITS Section 1.1 would also ensure that the affected systems rendered inoperable by isolation of an affected line are declared inoperable. Therefore, this deletion is administrative.

A.11 CTS Table 3.3.2-2 Footnote * refers to Bases Figure 3/4.3-1. This Figure is providing information as to what reactor vessel water level the various reactor water instruments actuate, in comparison to one another. This information is already essentially contained in the Allowable Value column of this Table. Therefore, this reference is being deleted and is considered administrative.

A.12 CTS Table 3.3.2-2 Footnote *** modifies the Allowable Value for Trip Function 1.d.3), the Main Steam Line Tunnel Temperature — High MSL Lead Enclosure. The footnote requires that prior to the Allowable Value adjustment, the actual ambient temperature reading for all Operable channels in the lead enclosure area must be greater than or equal to the ambient temperature used as the basis for the Allowable Value (part a of the footnote), and a Surveillance is implemented in accordance with Note d of Table 4.3.2.1-1 (part c of the footnote). These two requirements have been deleted since they are duplicative of the requirement to perform the Surveillance. Proposed SR 3.3.6.1.2 is the Surveillance that meets the CTS Table 4.3.2.1-1 Note d requirement.
CTS 4.0.1 and proposed SR 3.0.1 require Surveillances to be met in the Modes or other specified conditions in the Applicability. SR 3.3.6.1.2 must be met

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A.12 (cont'd) prior to implementing an Allowable Value change, since the Note to the SR 3.3.6.1.2 requires it to be met when the Allowable Value is adjusted. If the SR is not performed prior to the Allowable Value adjustment, then as soon as the adjustment is made, the affected channels would be inoperable as required by proposed SR 3.0.1. Therefore, the CTS Table 3.3.2-2 Footnote ***, parts a and c are unnecessary and have been deleted.

A.13 The details in Table 4.3.2.1-1 Note (b) related to how to perform the CHANNEL CALIBRATION of thermocouples is deleted since it is duplicative of the definition of CHANNEL CALIBRATION in Section 1.1 of the ITS. This change is considered administrative since there is no change in the calibration method.

A.14 The CHANNEL FUNCTIONAL TEST (CFT) requirement for CTS Table 4.3.2.1-1 Trip Function 1.i.3), SLCS Initiation, has been deleted since it is redundant to the LOGIC SYSTEM FUNCTIONAL TEST (LSFT). The SLC System Initiation channels have no adjustable setpoints, but are based on switch manipulation. The LSFT (proposed SR 3.3.6.1.6), which applies to ITS Table 3.3.6.1-1 Function 4.g (SLC System Initiation), tests all contacts and will provide proper testing of the channels tested by a CFT. Therefore, this deletion is considered administrative.

A.15 CTS Table 4.3.2.1-1 requires a CHANNEL FUNCTIONAL TEST (CFT) of Trip Functions 1.m and 2.g, the Manual Initiation Functions, every 92 days. Note (c) modifies this requirement such that the Manual Initiation switches are required to be tested every 18 months, while the remaining circuitry associated with the Manual Initiation Function is required to receive a CFT every 92 days as part of the circuitry required to be tested for automatic system actuation. The automatic logic circuitry that is common with the manual logic circuitry is not tested every 92 days. The automatic logic for most Functions is either one-out-of-one or two-out-of-two logic. However, when a CFT is performed on the automatic initiation channels, the logic that is common to the manual logic is not required to be tested (the channel loses identity prior to initiating the logic parts that are common). Therefore, the 92 day CFT does not actually require any testing of the Manual Initiation logic. The logic is tested completely when the switches are tested; every 18 months. CTS 4.3.2.2 and proposed SR 3.3.6.1.6 require a Logic System Functional Test (LSFT) every 18 months (changed to 24 months - see Discussion of Change LD.1 below). Since the LSFT is a complete test of the logic, including the Manual Initiation switches, there is no need to require a CFT. Therefore, ITS 3.3.6.1 only requires an LSFT, and this change is considered administrative.

ADMINISTRATIVE (continued)

A.16 For certain Functions in CTS Table 3.3.2-1, the total number of channels per trip system are listed in lieu of listing the number of channels per trip system on an area or room basis. The format of the ITS is to provide the number of channels per trip system on an area or room basis. This is also consistent with the manner in which the channels for the Main Steam Line High Flow Function (CTS Table 3.3.2-1 Trip Function 1.c.3, ITS Table 3.3.6.1-1 Function 1.c) is presented. Therefore, the following changes have been made:

a) CTS Table 3.3.2-1 Trip Function 1.d.3, the Main Steam Line Tunnel Lead Enclosure Temperature - High Function, requires 6 total channels per trip system. There are three areas (east, west, and center) monitored for this Function, with two channels per area in each trip system. Therefore, in ITS Table 3.3.6.1-1 Function 1.g, the required channels per trip system is listed as 2 per area. The number of areas and total channels are also described in the Bases for the individual Function.

b) CTS Table 3.3.2-1 Trip Function 1.f, the RHR Equipment Room Area Temperature - High Function, requires 2 total channels per trip system. There are two areas (heat exchanger and pump) monitored for this Function, with one channel per area in each trip system. Therefore, in ITS Table 3.3.6.1-1 Functions 3.g and 5.a, the required channels per trip system is listed as 1 per area. The number of areas and total channels are also described in the Bases for the individual Functions.

c) CTS Table 3.3.2-1 Trip Functions 1.j.1) and 1.j.2), the RWCU Pump Rooms A and B Temperature - High Functions, require 2 total channels per trip system. There are two pump rooms monitored, A and B, for these Functions, with one channel per room in each trip system. Therefore, since the two Trip Functions monitor the same System, these two Trip Functions have been combined into one Function in ITS Table 3.3.6.1-1: Function 4.d. The required channels per trip system is listed as 1 per room. The number of rooms and total channels are also described in the Bases for the individual Function.

d) CTS Table 3.3.2-1 Trip Functions 1.k.1), 1.k.2), and 1.k.3), the Reactor Building Pipe Chase Area Temperature - High Functions, require 4 total channels per trip system. There are three azimuthal areas monitored, 180° upper, 40°, and 180° lower, for these Functions, with one channel per area in each trip system for the first two areas and two channels in each trip system for the third area.

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A.16 (cont'd) Therefore, since the three Trip Functions monitor the same parameter, these three Trip Functions have been combined into one Function for each of the three affected Systems (i.e., RCIC, RWCU, and RHR SDC Parameter) in ITS Table 3.3.6.1-1: Functions 3.h, 4.e, and 5.d, respectively. The required channels per trip system is listed as 1 per area. The number of areas and total channels are also described in the Bases for the individual Functions. In addition, for clarity, the channels are described in ITS Table 3.3.6.1-1 based on the elevation in lieu of the azimuth.

B

e) CTS Table 3.3.2-1 Trip Function 1.1, the Reactor Building General Area Temperature - High Function, requires 5 total channels per trip system. There are five areas monitored for this Function, with one channel per area in each trip system. Therefore, in ITS Table 3.3.6.1-1 Functions 3.i and 5.e, the required channels per trip system is listed as 1 per area. The number of areas and total channels are also described in the Bases for the individual Functions.

Describing the channels in this manner does not technically change the current requirements; the total number of channels required for each of the affected Functions remains the same. Therefore, this change is considered administrative.

RELOCATED SPECIFICATIONS

R.1 The RCIC Drywell Pressure — High Function (CTS Table 3.3.2-1 Trip Function 2.h) isolates the RCIC turbine exhaust vacuum breaker isolation valves (2ICS*MOV148 and 2ICS*MOV164) coincident with a RCIC Steam Line Pressure — Low signal (CTS Table 3.3.2-1 Trip Function 2.b). However, these valves are not assumed in any design basis accident or transient analysis. Further, the evaluation summarized in NEDO-31466 determined the loss of this instrumentation to be a non-significant risk contributor to core damage frequency and offsite release. Therefore, the requirements specified for this Function did not satisfy the NRC Policy Statement Technical Specification screening criteria as documented in the Application of Selection Criteria to the NMP2 Technical Specifications and has been relocated to the Technical Requirements Manuals (TRM). The TRM will be incorporated by reference into the NMP2 USAR at ITS implementation. Changes to the TRM will be controlled by the provisions of 10 CFR 50.59.

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The CTS Tables 3.3.2-1 and 4.3.2.1-1 Trip Function 1.a.3 Applicability for the Reactor Vessel Water Level — Low, Level 3 Function has been changed to include MODES 4 and 5. This Function isolates the RHR Shutdown Cooling (SDC) System valves (Group 5) and these new Applicabilities will protect against potential draining of the reactor vessel through the RHR SDC suction line during shutdown conditions, which is when the RHR SDC System is normally operated. In addition, when RHR System integrity is maintained in MODES 4 and 5, only one of the two low water level instrumentation trip systems will be required. This is provided in ITS Table 3.3.6.1-1 Note (d). With the piping intact and no maintenance being performed that has a potential for draining the reactor vessel through the RHR System, both trip systems are not required since one trip system can isolate the suction piping (by closing one of the suction isolation valves). An appropriate ACTION (ITS 3.3.6.1 ACTION J) has also been added for when the channel(s) of the Function is inoperable in MODES 4 and 5. This is an additional restriction on plant operations and is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1.

M.2 The number of required channels for the Groups 3, 6, and 7 PCIV Manual Initiation Function (CTS Table 3.3.2-1 Trip Function 1.m) has been increased from "1" per trip system to "4" per trip system in ITS Table 3.3.6.1-1 Functions 2.d and 4.h. The design of the Groups 3, 6, and 7 logic is two switch and push buttons per trip system, with both being required to actuate a trip system. Currently, only one switch and push button per trip system is required. Therefore, this part of the change is more restrictive on plant operation and will ensure these groups can be manually actuated. In addition, each of the switch and push button channels provides two inputs to the isolation logic; one input actuated by rotating a collar switch and a second input by depressing the inner push button. Therefore, using the ITS format that each input is considered a channel, the minimum channels is more appropriately specified as "4." Since this part of the change involves no design change but is only a difference in nomenclature, it is considered administrative.

M.3 One additional Function has been added, ITS Table 3.3.6.1-1 Function 3.k. This Function is a Timer Function which delays initiation of the RHR/RCIC Steam Flow — High Function. Currently, the RHR/RCIC Steam Flow — High Function isolates the RCIC PCIVs only after a time delay. The actual time delay Allowable Value is controlled in plant procedures. Appropriate ACTIONS and Surveillance Requirements have also been added. This change is an additional restriction on plant operation.

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M.4 Footnote ** to CTS Tables 3.3.2-1 and 4.3.2.1-1 states that Trip Function 1.e, Condenser Vacuum — Low, is only required to be Operable in Modes 2 and 3 when any main turbine stop valve is ≥ 90% open or when the key-locked condenser low vacuum bypass switch is in the normal position. ITS Table 3.3.6.1-1 Note (a) requires the Condenser Vacuum — Low Function to be Operable in Modes 2 and 3 when any turbine stop valve is not closed. The current footnote essentially allows a stop valve to open up to 90% before requiring a MSIV isolation on low vacuum. The ITS will ensure that with a low vacuum condition, an MSIV isolation will occur if any turbine stop valve is not closed. This will ensure that the main condenser is not overpressurized if a turbine stop valve is inadvertently opened with main condenser vacuum low. This change is more restrictive on plant operation. In addition, the bypass switch requirement is redundant to the turbine stop valve requirement. There is no requirement in the CTS to place the bypass switches in normal, thus they can be maintained in the bypass position until the unit is ready to open the turbine stop valves. Thus, the CTS essentially only requires the Function to be Operable based on turbine stop valve position. Therefore, the deletion of this part of the CTS allowance is considered administrative. The Bases however, will describe the purpose of the bypass switches and their effect on the logic.

M.5 A time delay setting Allowable Value has been added in proposed ITS Table 3.3.6.1-1 for Function 2.c, the SGT System Exhaust Radiation — High Function. Currently, no maximum time delay is provided in CTS Table 3.3.2-2, trip Function 1.h. This Function has an adjustable time delay setting. The new Allowable Value is ≤ 18.5 seconds. The Allowable Value is based on the current setpoint methodology and ensures that the primary containment purge valves (group 9 valves) close on high SGT System exhaust radiation to keep offsite doses below 10 CFR 100 limits. This change is an additional restriction on plant operation. 1B

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The detail in CTS 4.3.2.2 relating to methods (simulated automatic operations) for performing the LOGIC SYSTEM FUNCTIONAL TESTS are proposed to be relocated to the Bases. This detail is not necessary to ensure the OPERABILITY of the primary containment isolation instrumentation. The requirements of ITS 3.3.6.1 and proposed SR 3.3.6.1.6 are adequate to ensure the primary containment isolation instrumentation is maintained OPERABLE. Therefore, the relocated detail is not required to be in the ITS to provide

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) 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 System design and operational details in CTS Table 3.3.2-1 (the Value Groups operated by signal column and the logic description in Notes a, f, g, and h) are proposed to be relocated to the Bases. Details relating to system design and operation are unnecessary in the LCO. These details are not necessary to ensure the OPERABILITY of the primary containment isolation instrumentation. The requirements of ITS 3.3.6.1 and the associated Surveillance Requirements are adequate to ensure the primary containment isolation instrumentation is maintained 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.3 System design and operational details in CTS Table 3.3.2-4 (PCIVs associated with each valve group and the associated isolation signals) are proposed to relocated to the Technical Requirements Manual (TRM). Details related to system design and operation are unnecessary in the LCO. These details are not necessary to ensure the OPERABILITY of the primary containment isolation instrumentation. The requirements of ITS 3.3.6.1 and the associated Surveillance Requirements are adequate to ensure the primary containment isolation instrumentation is maintained OPERABLE. In addition, the ITS Bases specifies which valve groups are actuated by each primary containment isolation instrument Function (as described in Discussion of Change LA.2 above). Therefore, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. The TRM will be incorporated by reference into the NMP2 USAR at ITS implementation. Changes to the TRM will be controlled by the provisions of 10 CFR 50.59.

LB.1 CTS 3.3.2 Action b.1.a) requires that, when the number of OPERABLE channels is less than required by the Minimum OPERABLE Channels per Trip System requirement for one Trip System, the inoperable channel(s) must be placed in the tripped condition within 1 hour for trip functions without an OPERABLE channel. CTS 3.3.2 Action C.2.a)1) requires that, when the number of OPERABLE channels is less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, then after placing the inoperable channel(s) in one trip system in the tripped condition in 1 hour, the inoperable channel(s) in the remaining trip system must be placed in the tripped condition within 1 hour for trip functions without an OPERABLE channel. ITS 3.3.6.1 does not include these requirements.

TECHNICAL CHANGES - LESS RESTRICTIVE

LB.1 (cont'd) ITS 3.3.6.1 ACTION A establishes the requirement to place the inoperable channel(s) in trip within either 12 or 24 hours, which is consistent with CTS 3.3.2 Actions b.1.b), b.1.c), c.2.a)2), and c.2.a)3), irrespective of the number of inoperable channels in a trip system. For most Functions, two channels are required per trip system and are combined in a two-out-of-two logic. Thus, when one channel is inoperable, the trip system will not actuate to close the associated PCIV. Therefore, having a second channel inoperable is essentially the same as one channel inoperable, the associated valve will not receive an isolation signal. ITS 3.3.6.1 ACTION B continues to ensure that the isolation capability of a penetration is not lost for greater than 1 hour. In addition, for those trip systems that have only one channel, the CTS unnecessarily restricts the restoration time to 1 hour (since when one channel is inoperable, the trip system has no OPERABLE channels). These conditions (loss of all channels in a trip system) was evaluated in the reliability analyses of NEDC-30851-P-A, Supplement 2, March 1989 and NEDC-31677-P-A, July 1990, and found to be acceptable. These analyses are the basis for the current 12 hour and 24 hour restoration times in the CTS 3.3.2 Actions. The results of the NRC review of these generic reliability analyses as it relates to NMP2 is documented in the NRC Safety Evaluation Report (SER) dated May 11, 1993. The SER concluded that the generic reliability analyses are acceptable to NMP2 and that NMP2 meets all requirements of the NRC SERs accepting the generic reliability analyses.

LB.2 CTS Table 3.3.2-1 Note (b), which allows a delay in entering the associated Action statement during performance of Surveillances, has been clarified to provide direct indication of the intent of the current wording. The current words "provided at least one other OPERABLE channel in the same trip system is monitoring that parameter" are intended to ensure that the trip capability of the Function is maintained. However, it does not provide this assurance for all logic system designs. In addition, for those trips systems that have only one channel, the CTS unnecessarily restricts the plant from using the 6 hour allowance. Therefore, the Note has been modified in ITS 3.3.6.1 (Note 2 to the Surveillance Requirements) to state "provided the associated Function maintains isolation capability." This is the intent of the current Note and is based on previously conducted reliability analyses (NEDC-31677-P-A, July 1990, and NEDC-30851-P-A, Supplement 2, March 1989). The results of the NRC review of these generic reliability analyses as it relates to NMP2 is documented in the NRC Safety Evaluation Report (SER) dated May 11, 1993. The SER concluded that the generic reliability analyses are acceptable to NMP2 and that NMP2 meets all requirements of the NRC SERs accepting the generic reliability analyses.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST (LSFT) of CTS 4.3.2.2 (proposed SR 3.3.6.1.6), the ISOLATION SYSTEM RESPONSE TIME test of CTS 4.3.2.3 (proposed SR 3.3.6.1.7), and the CHANNEL FUNCTIONAL TEST (CFT) for the Manual Initiation Functions specified in CTS Table 4.3.2.1-1 Footnote (c) (changed to LSFT in Discussion of Change A.15 above) has been extended from 18 months to 24 months to facilitate a change in the refuel cycle from 18 months to 24 months. This SR ensures that Isolation Actuation Instrumentation logic will function as designed to ensure proper response during an analyzed event. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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. 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 small. Most instrument channels are tested on a more frequent basis during the operating cycle in accordance with CTS 4.3.2.1, the CFT. This testing of the isolation instrumentation ensures that a significant portion of the Isolation Actuation Instrumentation circuitry is operating properly and will detect significant failures of this circuitry. The PCIVs including the actuating logic is designed to be single failure proof and therefore, is highly reliable.

Based on the inherent system and component reliability and the testing performed during the operating cycle, the impact, if any, from this change on system availability is small. The review of historical surveillance data also demonstrated that there are no failures that would invalidate this conclusion. 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.

LE.1 The Frequency for performing the CHANNEL CALIBRATION Surveillance of current Surveillance 4.3.2.1 and Table 4.3.2.1-1 (proposed SR 3.3.6.1.5) has been extended from 18 months to 24 months to facilitate a change to the NMP2 refuel cycle from 18 months to 24 months. 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

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) for the allowable grace period specified in CTS 4.0.2 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 4.0.2 and proposed SR 3.0.2). The subject SR ensures that the Isolation instruments will function as designed during an analyzed event. Extending the SR Frequency is acceptable because the Primary Containment Isolation System along with the Isolation initiation logic is designed to be single failure proof and, therefore, is highly reliable. Furthermore, the impacted Isolation instrumentation has been evaluated based on make, manufacturer and model number to determine that the instrumentation's actual drift falls within the design allowance in the associated setpoint calculation. The following paragraphs, listed by CTS Trip Function number, identify by make, manufacturer and model number the drift evaluations performed:

Trip Function 1.a.1): Reactor Vessel Water Level - Low Low Low, Level 1

This function is performed by Rosemount 1153DB5 Transmitters and 510DU Master and Slave Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.a.2): Reactor Vessel Water Level - Low Low, Level 2.

This function is performed by Rosemount 1153DB5 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

Trip Function 1.a.3): Reactor Vessel Water Level - Low, Level 3

This function is performed by Rosemount 1153DB4 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.b: Drywell Pressure - High

This function is performed by Rosemount 1153GB5 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.c.2): Main Steam Line Pressure - Low

This function is performed by Rosemount 1153GB9 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

Trip Function 1.c.3): Main Steam Line Flow - High

This function is performed by Rosemount 1153DB7 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.d.1): Main Steam Line Tunnel Temperature - High

This function is performed by Pyco 102-9039-08 thermocouples and Riley 86-PTGF-EG temperature switches. The thermocouples are not required to be calibrated, therefore, no drift evaluation was performed. The Riley instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.d.2): Main Steam Line Tunnel Differential Temperature - High

This function is performed by Pyco 102-9039-08 thermocouples and Riley 86-VTFF-EG temperature switches. The thermocouples are not required to be calibrated, therefore, no drift evaluation was performed. The Riley instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.d.3): Main Steam Line Tunnel Lead Enclosure Temperature - High

This function is performed by Pyco 102-9039-08 thermocouples and Riley 86-PTGF-EG temperature switches. The thermocouples are not required to be calibrated, therefore, no drift evaluation was performed. The Riley instruments were evaluated by quantitative analysis and the results indicate that the

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.e: Condenser Vacuum — Low

This function is performed by Rosemount 1153AB5 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.f: RHR Equipment Area Temperature - High

This function is performed by Pyco 102-9039-08 thermocouples and Riley 86-PTGF-EG temperature switches. The thermocouples are not required to be calibrated, therefore, no drift evaluation was performed. The Riley instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.g: Reactor Vessel Pressure - High

This function is performed by Rosemount 1153GB9 Transmitters and 510DU Master and Slave Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) **Trip Function 1.h:** Standby Gas Treatment (SGT) System Exhaust Radiation - High

This function is performed by a Kaman KDB Radiation Detector, Kaman KMG Gas Process Monitor, Kaman KEM-P Local Microprocessor, and a Kaman KELIC-P Remote Indication and Control Unit. These instruments were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.i.1): RWCU System Differential Flow - High

This function is performed by Rosemount 1153DB4 Transmitters, Bailey 766 Signal Resistor Units (SRUs), Bailey 766 Square Root Extractors, Bailey 752 Summers, and Bailey 745 Flow Switches. The Bailey SRUs are non calibratable devices and were evaluated utilizing a qualitative analysis (i.e., engineering judgment). The Rosemount Transmitters, Bailey Square Root Extractors, Bailey 752 Summers, and Bailey 745 Flow Switches were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of both evaluations support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.i.2): RWCU System Differential Flow - High, Timer

This function is performed by Eagle HP51A634 time delay relays. The Eagle relays were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Functions 1.j.1) and 1.j.2): RWCU Pump Room Temperature - High

This function is performed by Pyco 102-9039-08 thermocouples and Riley 86-PTGF-EG temperature switches. The thermocouples are not required to be calibrated, therefore, no drift evaluation was performed. The Riley instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

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LE.1 (cont'd) **Trip Function 1.j.3):** RWCU Heat Exchanger Room Area Temperature - High

This function is performed by Pyco 102-9039-08 thermocouples and Riley 86-PTGF-EG temperature switches. The thermocouples are not required to be calibrated, therefore, no drift evaluation was performed. The Riley instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.k: Reactor Building Pipe Chase Temperature - High

This function is performed by Pyco 102-9039-08 thermocouples and Riley 86-PTGF-EG temperature switches. The thermocouples are not required to be calibrated, therefore, no drift evaluation was performed. The Riley instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.l: Reactor Building Temperature — High

This function is performed by Pyco 102-9039-08 thermocouples and Riley 86-PTGF-EG temperature switches. The thermocouples are not required to be calibrated, therefore, no drift evaluation was performed. The Riley instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 2.a: RCIC Steam Line Flow - Timer

This function is performed by Agastat E7012 series relays. The Agastat relays were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

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LE.1 (cont'd)

Trip Function 2.b: RCIC Steam Supply Pressure - Low

This function is performed by Rosemount 1153AB7 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 2.c: RCIC Steam Line Flow - High

This function is performed by Rosemount 1153DB5 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 2.d: RCIC Turbine Exhaust Diaphragm Pressure - High

This function is performed by Rosemount 1153GB6 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

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LE.1 (cont'd)

Trip Function 2.e: RCIC Equipment Area Temperature - High

This function is performed by Pyco 102-9039-08 thermocouples and Riley 86-PTGF-EG temperature switches. The thermocouples are not required to be calibrated, therefore, no drift evaluation was performed. The Riley instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 2.f: RCIC Steam Line Tunnel Temperature - High

This function is performed by Pyco 102-9039-08 thermocouples and Riley 86-PTGF-EG temperature switches. The thermocouples are not required to be calibrated, therefore, no drift evaluation was performed. The Riley instruments were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 2.i: RCIC/RHR Steam Flow - High

This function is performed by Rosemount 1153DB5 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is small as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history demonstrates that there are no failures that would invalidate the conclusion that the impact, if any, on system availability is small from a change to a 24 month surveillance

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LE.1 (cont'd) frequency. 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"

L.1 Trip setpoints listed in CTS Table 3.3.2-2 are not included in the ITS and all references to these setpoints in CTS 3.3.2 are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.6.1 reflects Allowable Values consistent with the philosophy of NUREG-1434, Rev. 1. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoints will either be in accordance with this Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, these trip setpoints are not required to be in the Technical Specifications to provide adequate protection of the public health and safety. 13

L.2 CTS Table 3.3.2-1 Action 20, which requires a unit shutdown, is required to be taken when a Reactor Vessel Water Level — Low Low Low, Level 1 channel is not placed in trip as required by CTS 3.3.2 Actions b and c. ITS 3.3.6.1 Required Action D.1 is proposed to be added to allow isolation of the affected main steam line in lieu of shutting down the unit. Some conditions may affect

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L.2 (cont'd) the isolation logic for only some of the main steam lines. In these cases, it is not necessary to require a shutdown of the unit; rather, isolation of the affected lines returns the system to a status where it can perform the remainder of its isolation function, and continued operation is allowed (although it may be at a reduced power level in MODE 2.)

L.3 CTS Table 3.3.2-1 Action 20, which requires a unit shutdown, is required to be taken when a Reactor Vessel Water Level — Low Low, Level 2 channel is not placed in trip as required by CTS 3.3.2 Actions b and c. This Function actuates Reactor Water Cleanup (RWCU) System valves as well as other primary containment isolation valves. ITS 3.3.6.1 ACTION F has been added to allow isolation of the affected penetration instead of requiring a unit shutdown, when only the RWCU System valves are affected. Isolation of the affected penetration performs the safety function of the instruments. When the Reactor Vessel Water Level — Low Low, Level 2 Function channels are inoperable, and only the RWCU System (Groups 6 and 7) valves are affected, operation can continue with these valves isolated. If the penetration is not isolated within 1 hour (as provided in ITS 3.3.6.1 ACTION F), the plant must be placed in MODES 3 and 4 in accordance with ITS 3.3.6.1 ACTION H.

L.4 CTS Table 3.3.2-1 Action 20, which requires a unit shutdown to MODE 4, is required to be taken when a Reactor Vessel Water Level — Low, Level 3 channel is not placed in trip as required by CTS 3.3.2 Actions b and c. This Function actuates RHR SDC System valves. ITS 3.3.6.1 ACTION J has been added to allow isolation of the affected penetration (ITS 3.3.6.1 Required Action J.2) instead of requiring a unit shutdown to MODE 4 (i.e., the unit is allowed to remain in MODE 3). Isolation of the affected penetration performs the safety function of the instruments. In addition, allowing the unit to remain in MODE 3 provides more alternatives to remove decay heat than when the unit is in MODE 4. However, this action (isolating the affected penetration) will result in a loss of shutdown cooling, and could in fact, result in a more significant safety problem than if the valves were left open with inoperable channels. Therefore, an additional Action (ITS 3.3.6.1 Required Action J.1) would require action to be immediately initiated to restore the channel(s) to OPERABLE status. The Bases describes circumstances under which each Required Action is to be taken. These new actions ensure that SDC is not interrupted when needed, yet also ensures action is continued to restore the channel(s) if this is the case.

L.5 The MODE 1 and 2 Applicability requirements for CTS Tables 3.3.2-1 and 4.3.2.1-1 Trip Function 1.a.3), Reactor Vessel Water Level — Low, Level 3, Trip Function 1.f, RHR Equipment Area Temperature — High, Trip Function 1.k, Reactor Building Pipe Chase Temperature — High, and Trip Function 1.l,

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L.5 (cont'd) Reactor Building Temperature — High have been deleted for the RHR SDC System (Group 5) valves. Trip Function 1.g (ITS Table 3.3.6.1-1 Function 5.c), Reactor Vessel Pressure — High, ensures that the RHR SDC System valves are isolated in MODE 1 and MODE 2 when above the RHR cut-in permissive pressure setpoint, since this Function isolates the valves when above the setpoint. When in MODE 2 below the setpoint, other Technical Specification requirements essentially ensure that RHR Shutdown Cooling is not in service (ITS 3.5.1 requires all LPCI to be OPERABLE in MODE 2, and with RHR aligned to the shutdown cooling mode, LPCI will be inoperable). In addition, plant procedures require that RHR be aligned to the LPCI mode, and the recirculation pumps to operating (which would necessitate securing the shutdown cooling mode) prior to entering MODE 2. Therefore, the MODE 1 and 2 requirements for these Functions have been deleted.

L.6 The Main Steam Line Radiation — High isolation of valve groups 1 (MSIV and MSL drains) and 2 (Recirculation System sample valves) is proposed to be deleted from the Technical Specifications. This proposed deletion involves the removal of the Main Steam Line Radiation — High Trip Function 1.c.1 in CTS Table 3.3.2-1, 3.3.2-2 (including Footnote **), and 4.3.2.1-1, and Isolation Signal C in CTS Table 3.3.2-4. In addition, the Main Steam Line Radiation — High Function for CTS 3.3.1, RPS Instrumentation, is proposed to be deleted. This is described in Discussion of Change L.4 for ITS 3.3.1.1. CTS Table 3.3.2-1 Note (e), the trip and isolation of the air removal pumps, is being moved to ITS 3.3.7.2, as described in Discussion of Change A.7 above. This proposed deletion of the isolation function is based on the BWR Owners' Group Licensing Topical Report NEDO-31400A dated July 9, 1987, the NRC Safety Evaluation Report (SER) for that document, and the information provided in this Discussion Of Change. Eliminating the Main Steam Line Radiation Monitor automatic reactor shutdown feature and Main Steam Isolation Valve (MSIV) isolation will result in the reduced potential for unnecessary plant transients caused by spurious Main Steam Line Radiation Monitor (MSLRM) actuation trips and will increase plant operational flexibility.

The Main Steam Line Radiation Monitor consists of four redundant radiation monitors located above the main steam lines in the main steam tunnel. The Main Steam Line Radiation Monitor was designed to provide an early indication of gross fuel failures. The original intention was to mitigate the release of activity due to a fuel failure by providing a scram signal to terminate the initiating event and a MSIV closure signal to assure containment of the release. However, no credit is taken for these signals in any design basis event for terminating the initiating event or assuring the release remains within accepted limits. The only design basis accident in which either the Main Steam Line Radiation Monitor scram or MSIV isolation functions are mentioned is the

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L.6 (cont'd) control rod drop accident. To be consistent with the requirements of Section 15.4.9 of the Standard Review Plan, all of the postulated radioactivity released from this accident is assumed to be released to the turbine and condenser before the isolation occurs. Hence, the isolation resulting from the Main Steam Line Radiation Monitors provides no benefit.

The Recirculation System sample valves MSLRM high radiation isolation is not required to ensure 10 CFR 100 and 10 CFR 50 Appendix A GDC 19 dose acceptance criteria are met. Also, area radiation monitors in the general area of the recirculation sample line and sample panel will alarm should dose rates on the sample lines increase significantly. The alarm response training which is part of the general employee training program along with the radiation protection program ensures that occupational exposures will be maintained in accordance with ALARA principles. Therefore, removal of the isolation signal will not have a significant impact on accident consequences, environmental releases, or occupational doses.

The NRC staff has concluded that removal of the Main Steam Line Radiation Monitor trips that automatically shutdown the reactor and close the MSIVs is acceptable and that Licensing Topical Report, NEDO-31400A may be referenced in support of an amendment request provided that:

a.) The applicant demonstrates that the assumptions with regard to input values (including power per assembly and X/Q, and decay times) that are made in the generic analysis of the Licensing Topical Report bound those for the plant.

Table 1 of this Discussion of Change provides a comparison of key input parameters and Table 2 compares the dose assessment between the NMP2 Updated Safety Analysis Report and the NEDO-31400A analysis assumptions. The higher power level for NMP2 is used to determine the source term. Other considerations enter into the final two hour Exclusion Area Boundary Dose, such as the atmospheric dispersion factor, X/Q. In this case the X/Q is approximately a factor of ten less than the NEDO-31400A values which more than offsets the higher power level for NMP2. All other parameters are the same or more conservative than the NEDO-31400A values. Tables 1 and 2 demonstrates that the generic analysis of the Licensing Topical Report is bounding for NMP2.

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L.6 (cont'd) b.) The applicant includes sufficient evidence (implemented or proposed operating procedures, or equivalent commitments) to provide reasonable assurance that significantly increased radioactivity levels in the main steam lines will be controlled expeditiously to limit both occupational and environmental releases.

NMP2 has, in place, procedures that ensure that any significant increase in the levels of radioactivity in the main steam lines is promptly controlled to limit environmental releases and on-site occupational exposures. NMP2 plant procedures will be enhanced to incorporate the considerations of this Technical Specification Amendment.

c.) The applicant standardizes the Main Steam Line Radiation Monitor and offgas radiation monitor setpoints at 1.5 times the Nitrogen-16 background dose rate at the monitor locations, and commits to promptly sample the reactor coolant for possible contamination if the MSLRM and/or the offgas radiation monitors exceed their alarm setpoint.

The Main Steam Line Radiation Monitor alarm setpoint is 1.5 times the Nitrogen-16 background at the monitor location. That alarm will trigger entry into a procedure which will require a reactor coolant sample to be obtained and analyzed. The offgas pretreatment monitor alarm/trip is set in accordance with the Off-site Dose Calculation Manual to satisfy CTS 3.11.2.7 (ITS 3.7.4). The Technical Specification basis for the setpoint is that, restricting the gross activity rate of noble gases from the main condenser offgas provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. CTS 3.11.2.7 (ITS 3.7.4) implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR 50.

Reasonable assurance is provided in the plant response to increased radiation levels as detected by the offgas pretreatment monitor. The pretreatment monitor is more sensitive to detecting noble gas activity than the Main Steam Line Radiation Monitor because the Nitrogen-16 source, dominating the radiation present at the Main Steam Line Radiation Monitor, has decayed prior to the pretreatment monitor. The offgas pretreatment radiation monitor alarm/trip setpoint is based on

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L.6 (cont'd) CTS 3.11.2.7 (ITS 3.7.4). As required by CTS 3.11.2.7 (ITS 3.7.4), a level of 350,000 μCi/sec as measured downstream of the recombiner will require restoring the radioactivity rate to within its limit within 72 hours or, within the next 12 hours, be in at least HOT SHUTDOWN. The response to the more sensitive pretreatment monitor will ensure that actions are taken to limit occupational doses and environmental releases.

In addition to causing an RPS trip, the main steam line high radiation signal provides an isolation signal to the MSIVs. Closure of these valves prevents use of the condenser as a heat sink to facilitate scram recovery. Unnecessary loss of the condenser challenges containment and can lead to emergency core cooling system actuations.

By eliminating the main steam line isolation function, it is possible to allow operators the option of permitting the release of activity via a controlled release path using the Offgas System. If the vessel is isolated and the main condenser air removal pump is secured, there is no means to remove activity trapped in the condenser. It is reasonable to assume that this activity could then leak directly to the atmosphere without treatment.

In an Anticipated Transient Without Scram situation, the MSIVs may be reopened, by bypassing the MSIV isolation interlock for low reactor pressure vessel water level, to re-establish the main condenser as a heat sink if there is no indication of gross fuel failure or a steam line break. If, after re-establishing the main condenser as a heat sink, gross fuel failure should occur, the operator is directed by emergency operating procedures to manually initiate closure of the MSIVs.

NEDO-31400A results indicate that removing the scram and main steam line isolation function will represent a reduction in transient initiating events which results in a 0.3% reduction in core damage frequency probability. The NMP2 Individual Plant Examination (SAS-TR-92-001, Revision 0) was referenced as a comparison to the above NEDO-31400A results. The NMP2 results yielded a 0.2% reduction in core damage frequency and a 0.5% reduction in early high radionuclide release frequency. Hence, the final result is a net improvement in safety.

The referenced topical report also evaluated the impact that removal of these functions would have on reactivity control system failure frequency. The results were a negligible increase (1.4E-09 events per year), which is offset by the relative large reduction in core damage frequency. Hence, the final result is a net improvement to safety.

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L.6 (cont'd) To summarize, the most significant operational impact with the existing MSLRM trip functions is the unnecessary scram and isolation of the reactor vessel. Subjecting the reactor system to unnecessary vessel isolations diminishes plant reliability, complicates scram recovery and is contrary to the concept of maximizing plant safety. Maintaining the steam jet air ejectors operational (condenser unisolated) during an event permits continued use of the Offgas System to process radioactivity during transients. Thus, the operator is able to maintain control over the pathway of a potential release.

Based on the above evaluation, the proposed change satisfies the criteria of NEDO-31400A for deletion of the MSLRM isolation function (except the air removal pumps and the associated isolation valve). Therefore, the proposed change is acceptable.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

TABLE 1

CONTROL ROD DROP ACCIDENT
COMPARISON OF KEY ANALYSIS INPUT VALUES
NEDO-31400A VS. NMP 2

PARAMETER	NEDO-31400A VALUE[1]	NMP2 UPDATED SAFETY ANALYSIS REPORT
Number of Failed Fuel Rods	850	770
Core Average Power (MWt)	1579	3536 (102%)
Relative Power Level of Failed Rods (fraction)	1.5	1.5
Power Level of Failed Rods (MWt)	0.12	0.11
Fission Product Release from Melted Rods MELTED NON-MELTED	 100% NG/50% Iodines 10% NG/10% Iodines	 100% NG/50% Iodines 10% NG/10% Iodines 30% Kr-85 (R.G. 1.25)
Mass Fraction of Melted Fuel	0.0077	0.0077
% of Fission Products Transported to Main Condenser	100% NG/10% Iodines	100% NG/10% Iodines
% Airborne of Fission Products in Main Condenser	100% NG/10% Iodines	100% NG/10% Iodines
Main Condenser Leakage[2]	1 % per day	1 % per day
Hydrogen Flow Rate to Recombiner - (Design Capability)	50-150 scfm	136 scfm
Air/Noble Gas Offgas Flow Rate	site specific	40 scfm
Thyroid Dose Conversion Factor	Regulatory Guide 1.109	TID-14844
Breathing Rates	Regulatory Guide 1.3	Regulatory Guide 1.3
Whole Body Dose Conversion Factor (Semi-Infinite Cloud)	Regulatory Guide 1.109	TID-14844
Radiological Consequences Evaluation Computer Code	CONACO3	DRAGON code
Dispersion Coefficient, X/Q 0-2 hour Exclusion Area Boundary [2] 0-2 hour Exclusion Area Boundary [3]	 2.5E-03 sec/m^3 3.0E-04 sec/m^3	 1.90E-04 sec/m^3 2.97E-05 sec/m^3
Charcoal Bed Holdup Times[3,4]	Kr = 20 Hours Xe = 15 days	Kr = 26.6 hours Xe = 20 days

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TABLE 1 (continued)

FOOTNOTES:

1. Except as noted in 2 and 3 below, values apply to the Control Rod Drop Accident (CRDA) both with MSIV isolation and without MSIV isolation.

2. Applies only to CRDA with MSIV isolation.

3. Applies only to CRDA without MSIV isolation and 100% of Noble Gas source term processed though the Offgas Treatment System.

4. For a CRDA without MSIV isolation, 100% of the Noble Gases are held-up in the Offgas Treatment system charcoal beds for a time; the Iodines are retained indefinitely in the charcoal beds.

TABLE 2

CONTROL ROD DROP ACCIDENT DOSE COMPARISON
NMP2 DESIGN BASIS VS. NEDO-31400A

Two Hour Exclusion Area Boundary	With Main Steam Line Isolation Updated Safety Analysis Report		NEDO- 31400A		Without Main Steam Isolation Updated Safety Analysis Report		NEDO-31400A	
	Dose (Rem)	% [1]	Dose (Rem)	% [1]	Dose (Rem)	% [1]	Dose (Rem)	% [1]
Whole Body	2.07E-02	0.35	3.1E-01	5.17	1.9E-02	0.32	5.5E-01	9.17
Thyroid	3.34E-01	0.45	4.3E+00	5.73	N/A	N/A	N/A	N/A

FOOTNOTE:

1. Percent of 25% of 10 CFR 100 (or 6 Rem Whole Body and 75 Rem Thyroid)

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.7 CTS Table 3.3.2-1 Action 27, the Action required when Trip Function 1.h or 1.m channels are inoperable and not tripped, requires establishment of the Reactor Building Integrity with Standby Gas Treatment System operating within 1 hour. This Action has been deleted since this does not compensate for inoperable containment purge isolation channels. With this Action taken, the unit is still allowed to continue purging the containment. In its place, ITS 3.3.6.1 ACTION F will instead require the isolation of the containment purge valves (Group 9 valves) within 1 hour with CTS Table 3.3.2-1 Trip Function 1.h (SGTS Exhaust - High) inoperable. With the monitor inoperable, isolation of the valves is considered appropriate since the function of the monitor is to isolate these valves if its setpoint is exceeded. Therefore, the safety function is accomplished and operation in the containment purge mode is not permitted until the monitor is repaired.

In addition, if the Manual Initiation Function (CTS Table 3.3.2-1, Trip Function 1.m) associated with the Group 8 and 9 valves is inoperable, the current action (ITS Table 3.3.2-1 Action 27) to establish Reactor Building Integrity is deleted. The Group 8 valves are miscellaneous PCIVs, and do not include purge system valves. Establishing Reactor Building Integrity does not compensate for the loss of the instrumentation. The current requirements of Group 8 valves in CTS Table 3.3.2-1 Action 25 as modified in Discussion of Change L.9 below (ITS 3.3.6.1 ACTIONS G and H) are considered adequate since it requires the affected penetration to be isolated (which is the function of the instrumentation) or a unit shutdown will be required (which exits the applicability of the instrumentation). For Group 9 valves, the proposed requirement is to isolate the associated penetration (ITS 3.3.6.1 ACTION G), which fulfills the post accident function of the isolation logic. B

L.8 CTS Table 3.3.2-1 Action 21, which requires the unit to be in STARTUP (Mode 2) with the associated isolation valves closed within 6 hours, is being changed in ITS 3.3.6.1 ACTION D to only require isolation of the associated main steam line within 12 hours. The requirement to isolate the affected main steam lines is a sufficient action with the Main Steam Line Flow — High, Main Steam Line Tunnel Temperature — High, Main Steam Line Tunnel Differential Temperature — High, Main Steam Line Tunnel Lead Enclosure Temperature — High, and Condenser Vacuum — Low Functions inoperable and will normally require being in MODE 2 to avoid a scram. The requirement to be in MODE 2 is therefore implicit and is deleted from ITS 3.3.6.1 Required Action D.1. In addition, some conditions may affect the isolation logic for only one main steam line. In these cases, it is not necessary to require a shutdown of the unit; rather, isolation of the affected line returns the system to a status where it can perform the remainder of the isolation function, and continued

TECHNICAL CHANGES - LESS RESTRICTIVE

L.8 (cont'd) operation is allowed. The time allowed to isolate the associated main steam lines is extended from the CTS time of 6 hours to 12 hours in ITS 3.3.6.1 Required Action D.1. The additional time is provided to allow for more orderly power reduction.

L.9 CTS Table 3.3.2-1 Action 25; which applies to CTS Table 3.3.2-1 Trip Function 1.m (Manual Isolation Pushbutton) for the Groups 1 and 8 valves, requires restoration of the Manual Isolation Function within 48 hours. ITS 3.3.6.1 ACTION G will allow the isolation of the affected penetration flow path within 24 hours in lieu of restoring the Function. If a small number of the Group 1 or 8 valves are affected by the inoperability of the Manual Isolation Function, it is possible to isolate the affected penetration and continue to operate. Isolating the affected penetration flow path conservatively compensates for the inoperability since the function of the Manual Isolation Pushbuttons is to isolate the associated penetration flow path. In addition, the penetration is required to be isolated within 24 hours, instead of the current 48 hour requirement (i.e., the penetration will only be allowed to remain unisolated for 24 hours in the ITS; the CTS allows the penetration to remain unisolated for 48 hours). However, if isolating the penetration could result in a reactor scram, then shutting down the plant, as allowed in ITS 3.3.6.1 ACTION H, is the preferred action.

L.10 The time allowed in CTS Table 3.3.2-1 Action 26 to isolate the associated penetration if a Manual Isolation Function is inoperable has been extended from 9 hours (8 hours to restore the channel and 1 hour to isolate the penetration) to 24 hours in ITS 3.3.6.1 ACTION G. The current time is considered overly conservative since the Manual Isolation Function is not assumed in any accident or transient analysis in the USAR; automatic Functions are the Functions assumed to isolate the penetration. In additions, other means exist in the control room for operators to isolate the affected penetrations (e.g., individual control switches). This change is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1.

L.11 CTS Table 3.3.2-1 Action 28 requires locking the affected system isolation valves closed when the CTS Table 3.3.2-1 Trip Function 1.f (RHR Equipment Area Temperature — High) or Trip Function 1.g (Reactor Vessel Pressure — High) is inoperable. ITS 3.3.6.1 Required Action F.1 only requires closure of the valve; locking is not required. The requirement to lock the valve is an additional administrative requirement to assist in ensuring the valve remains isolated. This requirement is not necessary to be in the ITS to ensure the valve remains closed. ITS LCO 3.0.2 states that when an LCO is not met, the Required Actions must be met. Thus, when the valve is closed (to isolate the affected penetration flow path), the valve must remain closed to comply

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L.11 (cont'd) with the Required Action. In addition, inadvertent movement of a closed valve is an unlikely occurrence since plant administrative controls are in place that govern operation of these valves. Plant personnel would only operate a closed valve using a plant procedure, and these procedures are controlled by ITS 5.4.1.a. Therefore, these procedures will also help ensure a closed valve is not inadvertently opened. The proposed ITS ACTION is also consistent with CTS Table 3.3.2-1 Action 22, which requires the same valves (i.e., Groups 5 and 10 valves) to only be closed, not locked closed, when CTS Trip Functions 1.k, 1.l, 2.a, 2.b, 2.c, 2.d, 2.e, 2.f, and 2.i, as applicable, are inoperable.

L.12 The CHANNEL FUNCTIONAL TEST of all Manual Initiation Functions in CTS Table 4.3.2.1-1 Footnote (c) is performed at least once per 18 months during shutdown. The proposed LOGIC SYSTEM FUNCTIONAL TEST (proposed SR 3.3.6.1.6) for these Functions (see Discussion of Change A.15 above for changes to this test) does not include this restriction on plant conditions that requires the Surveillance to be performed while shutdown. These Surveillances can be performed while operating without jeopardizing safe plant operations. The control of plant conditions appropriate to perform the test is an issue for procedures and scheduling and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction. As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specifications Surveillances that do not dictate plant conditions for the Surveillance.

L.13 A Note has been added to CTS 4.3.2.3 (proposed SR 3.3.6.1.7 that exempts the sensors for the Main Steam Line (MSL) Isolation Reactor Vessel Water Level — Low Low Low, Level 1, Main Steam Line Pressure — Low, and Main Steam Line Flow — High Functions (the only three Functions to which CTS 4.3.2.3 is applicable - see Discussion of Change A.4 above) from response time testing and allows the design sensor response time to be used in the determination of the ISOLATION SYSTEM RESPONSE TIME. Deletion of the response time test for these sensors was evaluated in NEDO-32291 "System Analysis for Elimination of Selected Response Time Testing Requirements," January 1994, and was determined to be acceptable provided the individual licensee referencing this NEDO in a plant specific license amendment request met several conditions stipulated in the generic SER approving NEDO-32291. The evaluation provided below is consistent with the guidance provided in the Staff's generic SER for NEDO-32291.

NMPC has performed a review of NEDO-32291 and determined that the NEDO generic analysis is applicable to NMP2. The equipment affected by the proposed change in the Technical Specifications are the Isolation Functions identified above. Prior to installation of a new transmitter/switch or following

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L.13 (cont'd) refurbishment of a transmitter/switch a hydraulic response time test will be performed to determine an initial sensor specific response time value. Applicable NMP2 procedures have been revised/written, as appropriate, to fulfill this recommendation. NMP2 currently does not utilize any transmitters or switches that use capillary tubes in any application that requires response time testing. Therefore, the recommendation that capillary tube testing be performed after initial installation and after any maintenance or modification activity that could damage the lines for transmitters and switches that use capillary tubes is not applicable to NMP2. Applicable calibration procedures have been revised, as appropriate, to include steps to input a fast ramp or a step change to system components during calibrations. Applicable calibration procedures have been revised, as appropriate, to assure that technicians monitor for response time degradation. In addition, technicians have received appropriate training to make them aware of the consequences of instrument response time degradation. Surveillance test procedures have been revised, as appropriate, to ensure calibrations and functional tests are being performed in a manner that allows simultaneous monitoring of both the input and output response of units under test. NMP2's compliance with the guidelines of Supplement 1 to NRC Bulletin 90-01, "Loss of Fill-Oil in Transmitters Manufactured by Rosemount," was reviewed and documented in a safety evaluation transmitted to NMPC by NRC letter dated January 18, 1995. The NRC's evaluation concluded that NMP2's responses to Bulletin 90-01 and Supplement 1 conform to the requested actions of the Bulletin. The elimination of response time testing does not affect NMPC's response to the Bulletin. The isolation system instrumentation components for which response time testing is proposed to be eliminated has been evaluated and found to be acceptable in NEDO-32291. NMPC has reviewed the vendor recommendations for these components and confirmed that they do not contain periodic response time testing requirements.

The application of the proposed footnote will allow NMPC to use design response time data for the sensor in the determination of the isolation system response time, and eliminate the requirement for a separate measurement of the sensor response time. The remainder of the channel will continue to be tested for response time. Other Technical Specification testing requirements such as CHANNEL CALIBRATION, CHANNEL FUNCTIONAL TEST, CHANNEL CHECK, AND LOGIC SYSTEM FUNCTIONAL TEST in conjunction with actions taken in response to NRC Bulletin 90-01 are sufficient to identify failure modes or degradations in instrument response times and assure operation of the analyzed instrument loops within acceptable limits. The elimination of the response time testing of the identified sensors will reduce the potential for

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L.13. (cont'd) inadvertent actuation of the isolation instrumentation. Accordingly, this change will reduce the likelihood of a plant transient due to an inadvertent isolation of the primary containment.

Accordingly, based on the above evaluation, which is consistent with the guidelines of the Staff's generic SER approving NEDO-32291, the proposed elimination of sensor response time is acceptable. The above change is similar to that approved by the NRC in License Amendment No. 184 for Brunswick Units 1 & 2.

L.14 A Required Action has been added to CTS Table 3.3.2-1, Action 22 (ITS 3.3.6.1 Required Action I.1), which allows the associated SLC subsystem to be declared inoperable in lieu of isolating the RWCU System. The purpose of the SLC System Initiation Function of the RWCU System (ITS Table 3.3.6.1-1 Function 4.g) is to ensure the SLC subsystems function properly and the injected boron is not removed from the Reactor Coolant System. Therefore, if the RWCU System is not isolated, the SLC System cannot perform its function. With the SLC System declared inoperable, the Actions of CTS 3.1.5 (LCO 3.1.7), which have been previously approved by the NRC, would apply. Therefore, this change is considered acceptable. B

ADMINISTRATIVE

A.5 (cont'd) listed in Notes (c) and (d), the SCIVs and SGT System, are not part of primary containment. In the ITS, the Secondary Containment Isolation Instrumentation is in a separate LCO (ITS 3.3.6.2) from the Primary Containment Isolation Instrumentation, therefore, this part of the Note is unnecessary and has been deleted.

A.6 CTS Table 3.3.2-1 Action 27 has been changed by replacing the use of the term REACTOR BUILDING INTEGRITY with the elements of the term SECONDARY CONTAINMENT INTEGRITY (the undefined term "REACTOR BUILDING INTEGRITY" is synonymous with the defined term "SECONDARY CONTAINMENT INTEGRITY") and clarifies the need to isolate SCIVs and start the associated SGT subsystem(s). The change is editorial in that all the individual requirements are specifically addressed by ITS 3.3.6.2 Required Actions C.1.1 and C.2.1. Therefore the change is a presentation preference adopted by the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. Refer also to the Discussion of Changes associated with the Definitions Section which addresses deletion of the SECONDARY CONTAINMENT INTEGRITY definition. B

A.7 CTS Table 3.3.2-2 Footnote * refers to Bases Figure 3/4.3-1. This Figure is providing information as to what reactor vessel water level the various reactor water instruments actuate, in comparison to one another. This information is already essentially contained in the Allowable Value column of this Table. Therefore, this reference is being deleted and is considered administrative.

A.8 The technical content of CTS 4.6.5.3.d.2 was divided into two Surveillances. The majority of this Surveillance is performed as proposed SR 3.3.6.2.5, a LOGIC SYSTEM FUNCTIONAL TEST (LSFT). The LSFT verifies that each automatic signal functions properly. The actual system functional test portion is performed in the ITS 3.6.4.3 Surveillance Requirements. This will ensure that the entire system is tested with proper overlap.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 CTS Table 4.3.2.1-1 does not require a Channel Check for Trip Functions 3.a and 3.b, the Exhaust Radiation — High Functions. A requirement to perform a Channel Check every 12 hours is being added for ITS 3.3.6.2 Functions 3

TECHNICAL CHANGES - LESS RESTRICTIVE

M.1 (cont'd) and 4. This will ensure that a gross failure of the instrument channels has not occurred. This change is more restrictive on plant operations.

"Generic"

LA.1 The details in CTS 4.3.2.2 and CTS 4.6.5.3.d.2.b relating to methods for performing the LOGIC SYSTEM FUNCTIONAL TEST (simulated automatic operation) and the system functional test of SGT system (use of simulated signals), respectively, are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the secondary containment isolation instrumentation. The requirements of ITS 3.3.6.2 and the associated Surveillance Requirements are adequate to ensure the secondary containment isolation instruments are maintained 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 System design and operational details of current Table 3.3.2-1 Notes (c) and (d) are proposed to be relocated to the Bases. Details relating to system design and operation (e.g., specific valves and systems affected) are unnecessary in the LCO. These details are not necessary to ensure the OPERABILITY of the secondary containment isolation instrumentation. The requirements of ITS 3.3.6.2 and the associated Surveillance Requirements are adequate to ensure the secondary containment isolation instruments are maintained 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.

LB.1 CTS 3.3.2 Action b.1.a) requires that, when the number of OPERABLE channels is less than required by the Minimum OPERABLE Channels per Trip System requirement for one Trip System, the inoperable channel(s) must be placed in the tripped condition within 1 hour for trip functions without an OPERABLE channel. CTS 3.3.2 Action C.2.a)1) requires that, when the number of OPERABLE channels is less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, then after placing the inoperable channel(s) in one trip system in the tripped condition in 1 hour, the inoperable channel(s) in the remaining trip system must be placed in the tripped condition within 1 hour for trip functions without an OPERABLE channel. ITS 3.3.6.2 does not include these requirements. ITS 3.3.6.2 ACTION A establishes the requirement to place the inoperable

TECHNICAL CHANGES - LESS RESTRICTIVE

LB.1 (cont'd) channel(s) in trip within either 12 or 24 hours, which is consistent with CTS 3.3.2 ACTIONS b.1.b), b.1.c), c.2.a)2), and c.2.a)3), irrespective of the number of inoperable channels in a trip system. For most Functions, two channels are required per trip system and are combined in a two-out-of-two logic. Thus, when one channel is inoperable, the trip system will not actuate to close the associated SCIVs and start the associated SGT subsystem. Therefore, having a second channel inoperable is essentially the same as one channel inoperable, the associated valve will not receive an isolation signal.
ITS 3.3.6.2 ACTION B continues to ensure that the isolation capability of a penetration is not lost for greater than 1 hour. In addition, for those trip systems that have only one channel, the CTS unnecessarily restricts the restoration time to 1 hour (since when one channel is inoperable, the trip system has no OPERABLE channels). These conditions (loss of all channels in a trip system) was evaluated in the reliability analyses of NEDC-30851-P-A, Supplement 2, March 1989 and NEDC-31677-P-A, July 1990, and found to be acceptable. These analyses are the basis for the current 12 hour and 24 hour restoration times in the CTS 3.3.2 Actions. The results of the NRC review of these generic reliability analyses as it relates to NMP2 is documented in the NRC Safety Evaluation Report (SER) dated May 11, 1993. The SER concluded that the generic reliability analyses are acceptable to NMP2 and that NMP2 meets all requirements of the NRC SERs accepting the generic reliability analyses. Under these conditions, the other Trip System maintains the isolation capability.

LB.2 CTS Table 3.3.2-1 Note (b), which allows a delay in entering the associated Action statement during performance of Surveillances, has been clarified to provide direct indication of the intent of the current wording. The current words "provided at least one other OPERABLE channel in the same trip system is monitoring that parameter" are intended to ensure that the trip capability of the Function is maintained. However, it does not provide this assurance for all logic system designs. In addition, for those trip systems that have only one channel, the CTS unnecessarily restricts the plant from using the 6 hour allowance. Therefore, the Note has been modified in ITS 3.3.6.2 (Note 2 to the Surveillance Requirements) to state "provided the associated Function maintains isolation capability." This is the intent of the current Note and is based on previously conducted reliability analyses (NEDC-31677-P-A, July 1990, and NEDC-30851-P-A, Supplement 2, March 1989). The results of the NRC review of these generic reliability analyses as it relates to NMP2 is documented in the NRC Safety Evaluation Report (SER) dated May 11, 1993. The SER concluded that the generic reliability analyses are acceptable to NMP2 and that NMP2 meets all requirements of the NRC SERs accepting the generic reliability analyses.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST of CTS 4.3.2.2 and CTS 4.6.5.3.d.2 (proposed SR 3.3.6.2.5) has been extended from 18 months to 24 months. These SRs ensure that Secondary Containment Isolation Instrumentation and Standby Gas Treatment (SGT) actuation logic will function as designed to ensure proper response during an analyzed event. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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. 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 small. The SCIVs and SGT System including the automatic actuating logic is designed to be single failure proof, and therefore, is highly reliable. In addition, major deviations in the instrumentation during the operating cycle will be detected since other surveillances are performed such as the CHANNEL CHECK and CHANNEL FUNCTIONAL TEST (proposed SRs 3.3.6.2.1 and 3.3.6.2.2) at a more frequent basis.

Based on the inherent system and component reliability and the testing performed during the operating cycle, the impact, if any, from this change on system availability is small. The review of historical surveillance data also demonstrated that there are no failures that would invalidate this conclusion. 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.

LE.1 The Frequency for performing the CHANNEL CALIBRATIONS of CTS 4.3.2.1 as specified in CTS Table 4.3.2.1-1 (proposed SR 3.3.6.2.4) has been extended from 18 months to 24 months to facilitate a change in the NMP2 refuel cycle from 18 months to 24 months. The subject SR ensures that the Secondary Containment isolation instrumentation and Standby Gas Actuation Instrumentation will function as designed during an analyzed event. The proposed change will allow these Surveillances to extend their 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 4.0.2 and proposed SR 3.0.2) to a 24 month Surveillance Frequency

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LE.1 (cont'd) (i.e., a maximum of 30 months accounting for the allowable grace period specified in CTS 4.0.2 and proposed SR 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. Extending the SR Frequency is acceptable because the isolation initiation logic is designed to be single failure proof, and therefore, is highly reliable. Furthermore, the impacted isolation instrumentation has been evaluated based on make, manufacturer, and model number to determine that the instrumentation's actual drift falls within the design allowance in the associated setpoint calculation. The following paragraphs, listed by CTS Trip Function number, identify by make, manufacturer and model number the drift evaluations performed:

Trip Function 1.a.2): Reactor Vessel Water Level - Low Low, Level 2

This function is performed by Rosemount 1153DB5 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Trip Function 1.b: Drywell Pressure - High

This function is performed by Rosemount 1153GB5 Transmitters and 510DU Master Trip Units. The Rosemount Trip Units are functionally checked and setpoint verified more frequently, and if necessary, recalibrated. These more frequent testing requirements remain unchanged. Therefore, an increase in the surveillance interval to accommodate a 24 month fuel cycle does not affect the Rosemount Trip Units with respect to drift. The Rosemount Transmitters were evaluated by quantitative analysis and the results indicate that the projected 30 month drift values for the instruments do not exceed the design allowance provided in the setpoint calculation for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) **Trip Functions 3.a, 3.b:** Reactor Building Above/Below the Refuel Floor Exhaust Radiation - High

This function is performed by Kaman KDB Radiation Detectors, Kaman KMG Gas Process Monitors, Kaman KEM-P Local Microprocessors, and Kaman KERIC Remote Indication and Control Units. The equipment drift was evaluated utilizing a qualitative analysis (i.e., engineering judgment). The results of this analysis support a 24 month fuel cycle surveillance interval extension.

Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is small as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history demonstrates that there are no failures that would invalidate the conclusion that the impact, if any, on system availability is small from a change to a 24-month surveillance frequency. 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"

L.1 Trip setpoints listed in CTS Table 3.3.2-2 are not included in the ITS and all references to these setpoints in CTS 3.3.2 are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.6.2 reflects Allowable Values consistent with the philosophy of NUREG-1434, Rev. 1. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoints will either be in accordance with this Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, these trip setpoints are not required to be in the Technical Specifications to provide adequate protection of the public health and safety.

L.2 The requirement to shutdown with inoperable Reactor Vessel Water Level — Low Low, Level 2 or Drywell Pressure — High Functions as required by CTS Table 3.3.2-1 Action 20 has been deleted and alternative actions have been provided in ITS 3.3.6.2 ACTION C consistent with current Action 27 (see Discussion of Change L.4 below for changes in the current Action 27). The requirement to shutdown has been deleted since the alternative actions will activate the associated equipment required to function, consistent with the actions of the instrumentation if the instrumentation logic were in the trip condition. Alternatively, the associated isolation valves or SGT Subsystem may be declared inoperable. If declared inoperable, the proposed Secondary Containment Isolation Valve Specification (ITS 3.6.4.2) and SGT System Specification (ITS 3.6.4.3) will provide appropriate shutdown actions consistent with these current shutdown actions.

L.3 CTS Tables 3.3.2-1 and 4.3.2.1-1 Trip Function 1.a.2, Reactor Vessel Water Level — Low Low, Level 2, is required to be Operable during CORE ALTERATIONS and operations with a potential for draining the reactor vessel as stated in Note * to the Table. Automatic secondary containment isolation capabilities on reactor vessel water level decreases are not necessary during CORE ALTERATIONS. CORE ALTERATIONS do not result in any increased potential for vessel draindown. If ongoing activities do involve a potential for draining the reactor vessel, the Applicability of ITS Table 3.3.6.2-1 Function 1 will still require the Reactor Vessel Water Level — Low Low, Level 2 Function to be Operable. Therefore, the ITS will not include the Applicability of CORE ALTERATIONS for this Function.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is small as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history demonstrates that there are no failures that would invalidate the conclusion that the impact, if any, on system availability is small from a change to a 24-month surveillance frequency. 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"

L.1 CTS Table 3.3.7.1-1 Action 74.a requires a channel to be placed in trip within 24 hours when one main control room ventilation radiation monitor in one or both trip systems is inoperable. Since no actions are provided if the channel(s) are not tripped, CTS 3.0.3, which requires a unit shutdown, would be required to be entered. In lieu of requiring a unit shutdown, ITS 3.3.7.1 ACTION D will allow the associated CREF subsystem to be placed in operation within 1 hour (Required Action D.1) or declared inoperable within 1 hour (Required Action D.2) when a channel is not tripped within 24 hours. When two main control room ventilation radiation monitors in one trip system are inoperable, CTS Table 3.3.7.1-1 Action 74.b requires placing the CREF System in operation within 6 hours if one of the two channels is not restored within 7 days. When two main control room ventilation radiation monitors in both trip systems are inoperable, CTS Table 3.3.7.1-1 Action 74.c requires placing the CREF System in operation within 1 hour. Since no actions are provided if the CREF System is not placed in operation, CTS 3.0.3, which requires a unit shutdown, would be required to be entered. In lieu of requiring a unit shutdown, ITS 3.3.7.1 Required Action D.2 will allow the associated CREF subsystem to be declared inoperable within 1 hour. B B

The deletion of the unit shutdown required by CTS 3.0.3 is acceptable since the alternative actions provided in the ITS will activate the associated CREF subsystem that is required to function, consistent with the actions of the CREF System instrumentation if the CREF System instrumentation logic were in the trip condition. Alternately, it is acceptable to declare the associated CREF subsystem inoperable since the associated CREF System Specification (ITS 3.7.2) will provide appropriate actions that are identical to actions taken when a CREF subsystem is inoperable for reasons other than inoperable B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) instrumentation. The current requirements are overly restrictive, in that if the associated CREF subsystem was inoperable for other reasons, a much longer restoration time is provided. (B)

L.2 CTS 4.7.3.e.2.(b) requires that the CREF System start on a LOCA signal, which is generated from drywell pressure high signals and reactor vessel water level low signals. Thus, this Surveillance Requirement requires that all channels of the drywell pressure high and reactor vessel water level low instrumentation be Operable to support Operability of the CREF System. The instrumentation section of the CTS does not have specific requirements for the CREF System LOCA signals; it only has requirements for the high radiation signals. Therefore, since there are no specific instrumentation requirements for the LOCA signals (other than this specific Surveillance Requirement), when a high drywell pressure or a reactor vessel water level low channel is inoperable, the associated CREF subsystem must be declared inoperable. In addition, the two signals are required when the CREF System is required to be Operable; i.e., in Modes 1, 2, and 3, when irradiated fuel is being handled in the secondary containment, during Core Alterations, and during operations with a potential for draining the reactor vessel. ITS Table 3.3.7.1-1 provides requirements that two channels per trip system be Operable for each of the two Functions. This portion of the change is administrative since the channels are currently required in the CTS. However, the Reactor Vessel Water Level — Low Low, Level 2 Function (ITS Table 3.3.7.1-1 Function 1) is only required to be Operable in Modes 1, 2, and 3, and during operations with a potential for draining the reactor vessel, while the Drywell Pressure — High Function (ITS Table 3.3.7.1-1 Function 2) is only required to be Operable in Modes 1, 2, and 3. Automatic CREF System initiation on reactor vessel water level decreases are not necessary during Core Alterations and handling of irradiated fuel in the secondary containment. These two activities do not result in an increased potential for vessel draindown. If ongoing activities do involve a potential for draining the reactor vessel, the Applicability of ITS Table 3.3.7.1-1 Function 1 will still require the Reactor Vessel Water Level — Low Low, Level 2 Function to be Operable. Automatic CREF System initiation on drywell pressure increases are not necessary during Core Alterations, handling of irradiated fuel in the secondary containment, and during operations with a potential for draining the reactor vessel. During these evolutions, the unit is normally not in Mode 1, 2, or 3; it is in Mode 4 or 5 or defueled (The only evolution that can be performed in Modes 1, 2, and 3 is handling of irradiated fuel in the secondary containment, and since the Modes 1, 2, and 3 Applicability is still required, the evolution is covered in these Modes). In these Modes or condition, neither the primary containment nor its support functions (primary containment air lock and PCIVs) are required to be Operable. This allows the primary containment to be breached or the air

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) lock doors to be open. Therefore, it is not possible to receive a high drywell pressure signal, nor is it possible to actually pressurize the primary containment (since the reactor is depressurized). As such, requiring the Drywell Pressure — High Function to be Operable does not provide any real safety benefit.

L.3 CTS 4.7.3.e.2.(b) requires that the CREF System start on a LOCA signal, which is generated from drywell pressure high signals and reactor vessel water level low signals. Thus, this Surveillance Requirement requires that all channels of the drywell pressure high and reactor vessel water level low instrumentation be Operable to support Operability of the CREF System. Since there are no specific Actions when the instrumentation is inoperable, when a high drywell pressure or a reactor vessel water level low channel is inoperable, the associated CREF subsystem must be declared inoperable and the associated CTS 3.7.3 Actions taken. The CTS 3.7.3 Actions generally require restoration of the inoperable CREF subsystem. ITS Required Action D.2 requires declaring the associated CREF subsystem inoperable when an inoperable channel is not placed in trip within 24 hours (See Discussion of Change LB.2 above for the discussion of the 24 hour allowance). When declared inoperable, the appropriate actions of ITS 3.7.2, CREF System, are required to be taken, and these actions are consistent with the Actions of CTS 3.7.3, as modified by the Discussion of Changes for ITS 3.7.2. In lieu of declaring the associated CREF subsystem inoperable, ITS Required Action D.1 has been added to allow placing the associated CREF subsystem in the pressurization mode of operation. Placing the associated CREF subsystem in the pressurization mode is the actual function of the instrumentation. Therefore, once placed in operation, the function of the instrumentation has been completed and operation can continue for an unlimited amount of time. As stated in the Bases, the subsystem must be placed in operation in such a manner that it will return to operation upon restoration of power following loss of power event, since this is also part of the design basis of the CREF System. This will ensure that the CREF System can continue to meet its design function.

ADMINISTRATIVE (continued)

A.6 CTS Table 3.3.2-1 for the Isolation Actuation Instrumentation, contains a requirement for two channels per trip system (two trip systems) for the Main Steam Line Radiation — High Function. ITS LCO 3.3.7.2 presents the CTS requirement as requiring four total channels to be OPERABLE. The CTS and ITS require the same number of channels to be OPERABLE. Therefore, this change is a presentation preference and is considered to be administrative.

A.7 CTS Table 3.3.2-2 Footnote ** allows the Allowable Value and Trip Setpoint of the Main Steam Line Radiation — High Function to be adjusted upward to account for a higher background level prior to the start of a hydrogen injection test. Proposed SR 3.3.7.2.3, which provides the Allowable Value (the Trip Setpoint is deleted as described in Discussion of Change L.1 below), will not include this allowance; the Allowable Value for this specific Function will not be allowed to be raised to perform the test. While this appears to be a more restrictive change, the Footnote states that the allowance to raise the Allowable Value is only applicable if reactor power is > 20% RTP. The mechanical vacuum pumps are not allowed to be operated at this power level. This is enforced by a requirement in plant operating procedures, which precludes operating the mechanical vacuum pump at > 5% RTP. Therefore, at the power level necessary to perform the hydrogen injection test, the mechanical vacuum pumps would not be in service, thus ITS 3.3.7.2 would not be applicable. Due to this restriction, this deletion of Footnote ** is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 If the main steam line radiation channel(s) are inoperable due to a breaker that will not open or a valve that will not close, placing the channels in the tripped condition, as required by CTS 3.3.2 Actions b.1, c.1, and c.2.a), will not accomplish the intended restoration of the functional capability. In order to address these concerns, ITS 3.3.7.2 Required Action A.1 is added to specify restoration of the inoperable channel(s) and a Note is added to Required Action A.2 which states that placing a channel in trip is not applicable if the inoperable channel is the result of an inoperable isolation valve or vacuum pump breaker. Thus, if the main steam line radiation channel(s) are inoperable due to a breaker that will not open or a valve that will not close, the ITS 3.3.7.2 Required Action A.2 option of placing a channel in trip cannot be used

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 (cont'd) since the Note to the Required Action precludes its use under this condition. The only remaining option left in ITS 3.3.7.2 ACTION A is to meet Required Action A.1, which requires the channel to be restored. To restore the channel under the above described inoperability, the breaker or valve will have to be restored. Currently, the CTS does not require restoration when the channel is inoperable due to an inoperable breaker or valve; it only requires tripping of the channel. Therefore, the combination of proposed Required Action A.1 and the Note to Required Action A.2 will ensure that the functional capability of the mechanical vacuum pump isolation is restored within the allowed Completion Time when a channel is inoperable due to a mechanical vacuum pump breaker or isolation valve is inoperable. The addition of these requirements is more restrictive on plant operation. B

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details in Note (e) to CTS Table 3.3.2-1, which state that the main steam line radiation high function also trips and isolates the air removal pumps, are proposed to be relocated to the Bases. This detail is not necessary to ensure the OPERABILITY of the mechanical vacuum pump isolation instrumentation. The requirements of ITS 3.3.7.2 and associated Surveillance Requirements are adequate to ensure the mechanical vacuum pump isolation instrumentation is maintained OPERABLE. Therefore, 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.

LB.1 CTS 3.3.2 Action c.1 requires placing the inoperable channel(s) in one trip system in the tripped condition within one hour when the number of OPERABLE channels is less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems. The CTS action is required to be taken if one or both channels are inoperable in the trip system, even if the trip system is still capable of performing its trip function. The four channels of the Main Steam Line Radiation — High Function are arranged with two channels in each of two trip systems, in a one-out-of-two taken twice trip logic. With one channel inoperable in one or both trip systems, trip capability is still maintained, thus the CTS one hour action allowance in this situation is overly restrictive. As long as mechanical vacuum pump isolation capability is maintained, ITS 3.3.7.2 Action A allows 12 hours to place the channel(s) in trip. If more than one channel is inoperable in one or both trip systems, then

TECHNICAL CHANGES - LESS RESTRICTIVE

LB.1 (cont'd) isolation capability is not maintained and the provisions of ITS 3.3.7.2 Action B, consistent with the CTS, allows only 1 hour to restore mechanical vacuum pump isolation capability.

The proposed change in the CTS action to allow 12 hours (as long as isolation capability is maintained) to place a channel(s) in trip is supported by the reliability analysis of NEDC-30851-P-A, Supplement 2, March 1989. This analysis is the basis for the current 12 hour restoration time in the CTS 3.3.2 Actions. The results of the NRC review of this generic reliability analysis as it relates to NMP2 is documented in the NRC Safety Evaluation Report (SER) dated May 11, 1993. The SER concluded that the generic reliability analysis is acceptable to NMP2 and that NMP2 meets all requirements of the NRC SER accepting the generic reliability analysis.

LD.1 The Frequency for performing the LOGIC SYSTEM FUNCTIONAL TEST (LSFT) of CTS 4.3.2.2 (proposed SR 3.3.7.2.4), has been extended from 18 months to 24 months to facilitate a change in the refuel cycle from 18 months to 24 months. This SR ensures that mechanical vacuum pump isolation actuation instrumentation logic will function as designed to ensure proper response during an analyzed event. The proposed change will allow this Surveillance to extend its 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 4.0.2 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 4.0.2 and proposed SR 3.0.2). This proposed change, as associated with the main steam line radiation monitors, 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. 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 small. Most instrument channels are tested on a more frequent basis during the operating cycle in accordance with CTS 4.3.2.1, the CFT. This testing of the mechanical vacuum pump isolation instrumentation ensures that a significant portion of the circuitry is operating properly and will detect significant failures of this circuitry.

The condenser vacuum pump trip has not been historically surveilled. This has been duly addressed via the LER mechanism. Consequently, the surveillance history is not available to be evaluated as per NRC Generic Letter No. 91-04. Conversely, the reliability was assured at the time of the CTS non-compliance.

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) Though the surveillance had never been performed in the life of the plant, the trip function was tested satisfactorily. Review of the equipment history also substantiates the equipment's reliability. It is considered that this provides reasonable assurance that the condenser vacuum pump trip is reliable and the surveillance extension from 18 months to 24 months does not present a significant impact to safety.

Based on the inherent system and component reliability and the testing performed during the operating cycle, the impact, if any, from this change on system availability is small. The review of historical surveillance data also demonstrated that there are no failures that would invalidate this conclusion. 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.

LE.1 The Frequency for performing the CHANNEL CALIBRATION Surveillance of CTS 4.3.2.1 and Table 4.3.2.1-1 (proposed SR 3.3.7.2.3) has been extended from 18 months to 24 months to facilitate a change to the NMP2 refuel cycle from 18 months to 24 months. 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 4.0.2 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 4.0.2 and proposed SR 3.0.2). The subject SR ensures that the mechanical vacuum pump isolation instruments will function as designed during an analyzed event. Extending the SR Frequency is acceptable because the isolation initiation logic is designed to single failure proof and, therefore, is highly reliable. Furthermore, the impacted Isolation instrumentation has been evaluated based on make, manufacturer and model number. It was determined that the instrument drift is not significant in relation to the monitored parameter and will have a non-detectable impact on instrument loop drift values when combined with the large accuracy values for the instrumentation. The Main Steam Line Radiation — High Function is performed by General Electric (GE) ion chamber detectors, GE NUMAC Log Rad Monitors and GE Trip Auxiliary Units. The GE Radiation Monitoring Instrumentation was evaluated utilizing a qualitative analysis (i.e., engineering judgment). The results of this analysis support a 24 month fuel cycle surveillance interval extension.

Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is small as a result of the change in the surveillance test interval.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history demonstrates that there are no failures that would invalidate the conclusion that the impact, if any, on system availability is small from a change to a 24 month surveillance frequency. 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"

L.1 Trip setpoints listed in CTS Table 3.3.2-2 are not included in the ITS and all references to these setpoints in CTS 3.3.2 are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.7.2 reflects Allowable Values consistent with the philosophy of NUREG-1434, Rev. 1. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoints will either be in accordance with this Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, these trip setpoints are not required to be in the Technical Specifications to provide adequate protection of the public health and safety. 1 B

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.2 CTS Tables 3.3.2-1 and 4.3.2.1-1 contain an Applicability of MODES 1, 2, and 3 for the Main Steam Line Radiation — High Function. ITS 3.3.7.2 only requires this Function to be Operable in MODES 1 and 2 with any mechanical vacuum pump in service and any main steam line not isolated. CTS Table 3.3.2-1 Action 21 requires the plant to be in at least Startup with the associated isolation valves closed within 6 hours or be in at least Hot Shutdown within 12 hours and in Cold Shutdown within the next 24 hours, if the Action provisions of CTS 3.3.2.b or c are not met. ITS 3.3.7.2 Action C is entered if the Required Action and associated Completion Times of Conditions A or B are not met. Proposed ACTION C contains four options: (1) Isolate the mechanical vacuum pumps within 12 hours; (2) Remove the associated vacuum pump breaker(s) from service; (3) Isolate the main steam lines within 12 hours; or (4) Be in MODE 3 within 12 hours.

The CTS Applicability of MODES 1, 2, and 3, is intended to address all the trips that are generated by the Main Steam Line Radiation — High Function, including MSIVs and MSL drain valves, recirculation sample valves, and mechanical vacuum pumps. All the trips except the mechanical vacuum pumps and associated isolation valve have been removed from the CTS (see the Discussion of Changes for ITS 3.3.6.1). The current Applicability of MODES 1, 2, and 3 is overly restrictive to define Operability requirements for only the mechanical vacuum pump and associated isolation valve. The isolation and trip of the mechanical vacuum pump(s) are necessary in MODES 1 and 2 when any pump is in service and any main steam line not isolated, to mitigate the consequences of a postulated control rod drop accident. When the mechanical vacuum pumps are not in service or all main steam lines are isolated in MODE 1 or 2, fission product release via this pathway will not occur. In MODE 3 the consequences of a control rod drop are insignificant, and are not expected to result in any fuel damage or fission product releases. Therefore, the isolation and trip of the mechanical vacuum pumps are not necessary in these conditions or Mode.

One of the changes to CTS Table 3.3.2-1 Action 21 removes the requirement to be in at least Startup when closing the associated isolation valve and extends this Completion Time from 6 hours to 12 hours in ITS 3.3.7.2 Action C. Another change to Action 21 removes the requirement to go to Cold Shutdown. ITS 3.3.7.2 Action C allows 12 hours to either isolate the mechanical vacuum pump, remove the associated vacuum pump breaker(s) from service, isolate the main steam lines, or be in MODE 3. It is not necessary to specify that the plant be in at least Startup if the mechanical vacuum pumps are isolated or tripped, since no releases via this pathway will occur. Also, if the main steam lines are isolated, there is no need to specify going to at least Startup, since the isolation action in and of itself will require the plant to be in at least MODE 2.

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) The proposed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions, to remove the mechanical vacuum pump from service, or to isolate the main steam lines, in an orderly manner and without challenging plant systems. The CTS requirement to go to Cold Shutdown is not necessary, since the applicability of proposed ITS 3.3.7.2 is exited by going to MODE 3. ITS 3.3.7.2 ACTION C adds the allowance to remove the associated vacuum pump breaker(s) from service as an option to the CTS requirement to close the associated isolation valve. This option is acceptable since without a vacuum pump running, releases via this pathway will be stopped.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history, demonstrates that there are no failures that would invalidate the conclusion that the impact, if any on system availability is minimal from a change to a 24-month surveillance frequency. 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"

L.1 Trip setpoints listed in CTS Table 3.3.3-2 are not included in the ITS and all references to these setpoints in CTS 3.3.3 are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. The NMP2 ITS 3.3.8.1 reflects Allowable Values consistent with the philosophy of NUREG-1434, Rev. 1. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the Instrument Setpoint Methodology used at NMP2. Thus, any changes to the trip setpoints will either be in accordance with this Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, these trip setpoints are not required to be in the Technical Specifications to provide adequate protection of the public health and safety.

A.1

Specification 3.3.8.2

ELECTRICAL POWER SYSTEMS

ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

REACTOR PROTECTION SYSTEM ELECTRIC POWER MONITORING (RPS LOGIC)

LIMITING CONDITIONS FOR OPERATION

LCO 3.3.8.2

3.8.4.4 Two RPS UPS electrical protection assemblies for each inservice UPS set or alternate source shall be OPERABLE. A.2 RPS logic bus

APPLICABILITY: At all times. L.1

ACTION:

ACTION A

a. With one RPS electrical protection assembly for an inservice RPS UPS inoperable, restore the inoperable electrical protection assembly to OPERABLE status within 72 hours or remove the associated RPS UPS from service. logic bus A.2 M.1

ACTION B

b. With both RPS electrical protection assemblies for an inservice RPS UPS inoperable, restore at least one electrical protection assembly to OPERABLE status within 30 minutes or remove the associated RPS UPS from service. 1 hour L.2 logic bus M.1 A.3

add proposed ACTION C

add proposed ACTIONS D, E, and F L.5 VB

SURVEILLANCE REQUIREMENTS

add Proposed Surveillance Requirement Note

4.8.4.4 The above specified RPS electrical protection assemblies instrumentation shall be determined OPERABLE: L.3

SR 3.3.8.2.1

a. By performance of a CHANNEL FUNCTIONAL TEST each time the plant is in COLD SHUTDOWN for a period of more than 24 hours, unless performed within the previous 6 months. LD.1 and LE.1

SR 3.3.8.2.2

b. At least once per 24 months by demonstrating the OPERABILITY of overvoltage, undervoltage and underfrequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic and output circuit breakers and verifying the following setpoints. L.4

SR 3.3.8.2.3

SR 3.3.8.2.2

1. Overvoltage Bus A: ≤ 137.8 volts AC
   Bus B: ≤ 137.8 volts AC

2. Undervoltage Bus A: ≥ 115.5 volts AC
   Bus B: ≥ 114.2 volts AC

3. Underfrequency ≥ 57 Hz

with time delay set to ≤ 4 seconds M.3

57.5 M.4

Page 1 of 1

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 (cont'd) power supply. This action will deenergize the associated RPS logic bus and result in a half scram, an isolation of most primary containment penetrations, isolations of the secondary containment penetrations, and start of one SGT and CREF subsystem. Since the unit cannot operate for any length of time in this configuration (mainly due to the primary containment isolation), the more prudent action, as described in the ISTS Bases, is to leave the RPS logic bus energized and to shutdown the unit. Therefore, the allowance to remain operating with the RPS UPS removed from service has been deleted and is considered more restrictive on plant operation.

M.2 Not used.

M.3 Time delay setting requirements have been added in proposed SR 3.3.8.2.2 for the overvoltage, undervoltage, and underfrequency protective devices of the RPS logic electric power monitoring assemblies. Currently, no maximum setting is provided in CTS 4.8.4.4.b. These devices have adjustable time delay settings. The new Allowable Value for all protective devices is $\leq$ 4 seconds. The Allowable Values are based on the current setpoint methodology and ensures that the devices trip to protect the equipment powered by the associated RPS logic bus. These Allowable Values are also consistent with the current settings of the devices. This change is an additional restriction on plant operation.

M.4 The underfrequency setpoint currently specified in CTS 4.8.4.4.b.3 is actually the Analytical Limit. Thus, NMP2 can currently continue to call the underfrequency trip Operable as long as the actual setpoint is greater than or equal to the Analytical Limit. NMP2 is currently maintaining the actual setpoint in accordance with the most recent setpoint calculation, to ensure the analytical limit is not exceeded. Proposed SR 3.3.8.2.2 includes the Allowable Value from this setpoint calculation, not the Analytical Limit. This is an additional restriction on plant operation since NMP2 will now be required to maintain the actual setpoint greater than or equal to the Allowable Value. This will ensure the RPS logic buses are providing $\geq$ 57 Hz to all equipment powered from the buses. The Bases of the ITS also provides this description.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LD.1 The Frequency for performing the system functional test of CTS 4.8.4.4.b has been extended from 18 months to 24 months in proposed SR 3.3.8.2.3. This SR ensures that RPS Electric Power Monitoring Instrumentation logic will function as designed to ensure proper response during an analyzed event. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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. The monitoring logic has been recently modified to implement highly reliable solid state sensing relays. Reviews of historical maintenance and surveillance data for the balance of the system 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 small. RPS Electric Power Monitoring channels are normally tested on a more frequent basis during the operating cycle in accordance with CTS 4.8.4.4.a (proposed SR 3.3.8.2.1). This testing of the RPS Electric Power Monitoring instrumentation, if performed, ensures that a significant portion of the RPS Electric Power Monitoring instrumentation circuitry is operating properly and will detect significant failures of this circuitry. If this testing is not performed, this change is still considered acceptable based on the historical data, and since the RPS Electric Power Monitoring instrumentation is designed to be single failure proof, and therefore, is highly reliable. Based on the modification and the inherent system and component reliability and the testing performed during the operating cycle, the impact, if any, from this change on system availability is small. The review of historical surveillance data also demonstrated that there are no failures that would invalidate this conclusion. In addition, the proposed 24 month Surveillance Frequencies, if performed at the maximum interval allowed by proposed SR (30 months) do not invalidate any assumptions in the past licensing basis.

LE.1 The Frequency for performing the CHANNEL CALIBRATION requirement of CTS 4.8.4.4.b has been extended from 18 months to 24 months in proposed SR 3.3.8.2.2. The subject SR ensures that the RPS Electric Power Monitoring System will trip at the specified Allowable Values. The proposed change will allow these Surveillances to extend their Surveillance Frequency from the

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) current 18 month Surveillance Frequency (i.e., a maximum of 22.5 months accounting for the allowable grace period specified in CTS 4.0.2 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 4.0.2 and proposed SR 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. Extending the SR Frequency is acceptable because the RPS Electric Power Monitoring instrumentation is designed to be highly reliable. Furthermore the impacted RPS Electric Power Monitoring instrumentation has been evaluated based on make, manufacturer and model number as compared to similar operating equipment with similar operating characteristics to determine the instrumentation's projected drift values. The following paragraphs, listed by CTS function number, identify by make, manufacturer and model number and drift evaluations performed:

1. Overvoltage

This function is performed by a Nuclear Logistics Model No. 411U6175-HF-L relay. The Nuclear Logistics relays were evaluated by quantitative analysis and the results indicate the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

2. Undervoltage

This function is performed by a Nuclear Logistics Model No. 411U6175-HF-L relay. The Nuclear Logistics relays were evaluated by quantitative analysis and the results indicate the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

3. Underfrequency

This function is performed by a Nuclear Logistics Model No. 422B1275-L relay. The Nuclear Logistics relays were evaluated by quantitative analysis and the results indicate the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd) Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is minimal as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history, demonstrates that there are no failures that would invalidate the conclusion that the impact, if any on system availability is minimal from a change to a 24-month surveillance frequency. 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"

L.1 CTS 3.8.4.4 requires the RPS logic bus EPAs to be OPERABLE at all times. The Applicability of ITS 3.3.8.2 is specified as MODES 1, 2, and 3, MODES 4 and 5 with both RHR SDC suction isolation valves open, MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, during movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, and during OPDRVs. With no control rods withdrawn from core cells containing fuel assemblies in MODE 5 and both RHR SDC suction isolation valves not open in MODE 4 or 5, there is no need for the RPS logic or RHR SDC isolation to function and therefore, there is no need to require their protection. With no movement of irradiated fuel assemblies in the secondary containment, no CORE ALTERATIONS, and no OPDRVs taking place, there is no need for the secondary containment isolation instrumentation and CREF System instrumentation to function and therefore, there is no need to require their protection. Therefore, the Applicability of CTS 3.8.4.4 has been changed to only include MODES 1, 2, and 3 and those MODES or Conditions other than MODES 1, 2, and 3 when the RPS, RHR SDC isolation, secondary containment isolation, or CREF System initiation functions (which are all the Technical Specification required equipment powered from the RPS logic buses) are required. In addition, ITS 3.10.1 requires secondary containment isolation instrumentation to be OPERABLE during system leakage and hydrostatic testing in MODE 4, and ITS 3.10.4 will allow a single control rod to be withdrawn in MODE 4 by allowing the Reactor Mode Switch to be in the Refuel position. Therefore, the RPS Electric Power Monitoring — Logic requirements have been included in ITS 3.10.1 and ITS 3.10.4. B B

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.2 The allowed out of service time of CTS 3.8.4.4 Action b for two inoperable assemblies is extended from 30 minutes to 1 hour in ITS 3.3.8.2 Required Action B.1 to provide sufficient time for the plant personnel to take corrective actions. The time extension for two inoperable assemblies is minimal but necessary to allow consideration of plant conditions, available personnel, and the appropriate actions.

L.3 This change proposes to add a Note to the Surveillance Requirements that will allow a 6 hour delay from entering into the associated Conditions and Required Actions for a channel placed in an inoperable status solely for performance of required Surveillances provided the other RPS electric power monitoring assembly for the associated RPS logic bus maintains trip capability. The loss of one electric power monitoring assembly is acceptable in this case since only one of the two assemblies is required to trip the associated power supply if power is not maintained within acceptable limits. The short period of time (6 hours) in this condition will have no appreciable impact on risk. Also, upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition must be entered and Required Actions taken.

L.4 The overvoltage and undervoltage setpoints for CTS 4.8.4.4.b.1 and 2 are actually the Trip Setpoints, not the Allowable Values. Proposed SR 3.3.8.2.2 now includes the Allowable Values, consistent with the philosophy of NUREG-1434. These Allowable Values (to be included in Technical Specifications) have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Value selection evaluation used actual NMP2 operating and surveillance trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The proposed Allowable Values have been established from each design or safety analysis limit by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.5 CTS 3.8.4.4 does not provide any actions if the RPS EPAs are not restored or the associated RPS UPS is not removed from service (which de-energizes the associated RPS logic bus), as required by Actions a and b. Thus, CTS 3.0.3 is required to be entered. However, since CTS 3.0.3 is not applicable in Modes 4 and 5, 10 CFR 50.36(c)(2) requires that the licensee notify the NRC if required by 10 CFR 50.72, and an Licensee Event Report (LER) be submitted to the NRC as required by 10 CFR 50.73. In lieu of these two requirements, three new ACTIONS are provided if the Required Actions of Condition A or B are not met in MODES other than MODES 1, 2, and 3. ITS 3.3.8.2 ACTION D requires action to be initiated to restore one EPA to OPERABLE status for each RPS logic bus (ITS 3.3.8.2 Required Action D.1) or to isolate the Residual Heat Removal (RHR) Shutdown Cooling (SDC) System (ITS 3.3.8.2 Required Action D.2). ITS 3.3.8.2 ACTION E requires action to be initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. ACTION F requires action to be taken to isolate the affected secondary containment penetration flow paths and start the associated SGT and CREF subsystems, or to declare the associated SCIVs, SGT subsystems, and CREF subsystems inoperable. These actions place the reactor in the least reactive condition and ensures either the safety function of the RPS, primary containment isolation system, secondary containment isolation system, and CREF System will not be required or is already met. The option (Required Action D.1) is given to continue to restore an assembly to OPERABLE status since there may be a need for RHR SDC System. Alternately, Required Actions F.1.2, F.2.2, and F.3.2, which require declaring the associated SCIVs, SGT subsystem(s), and CREF subsystem(s) inoperable, are acceptable since the individual Specifications (ITS 3.6.4.2, ITS 3.6.4.3, and ITS 3.7.2, respectively) will provide appropriate actions that are consistent with actions taken when an SCIV, SGT subsystem, or CREF subsystem is inoperable for reasons other than inoperable RPS EPAs.

B

A.1

Specification 3.3.8.3

ELECTRICAL POWER SYSTEMS

ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

REACTOR PROTECTION SYSTEM ELECTRIC POWER MONITORING (SCRAM SOLENOIDS)

LIMITING CONDITIONS FOR OPERATION

LCO 3.3.8.3

3.8.4.5 Two RPS electrical protection assemblies (EPAs) for each inservice RPS MG set or alternate source shall be OPERABLE. A.2

APPLICABILITY: At all times. L.1

RPS scram solenoid bus

ACTION:

ACTION A

a. With one RPS electrical protection assembly for an inservice RPS MG set or alternate power supply inoperable, restore the inoperable EPA to OPERABLE status within 72 hours or remove the associated RPS MG set or alternate power supply from service. A.3 A.2 scram solenoid bus

ACTION B

b. With both RPS electrical protection assemblies for an inservice RPS MG set or alternate power supply inoperable, restore at least one EPA to OPERABLE status within 30 minutes or remove the associated RPS MG set or alternate power supply from service. A.3 A.2 scram solenoid bus 1 hour L.2

add proposed ACTION C A.4

add proposed ACTION D L.5 | 6

SURVEILLANCE REQUIREMENTS

add proposed Surveillance Requirements Note L.3

4.8.4.5 The above specified RPS electrical protection assemblies shall be determined OPERABLE:

SR 3.3.8.3.1

a. By performance of a CHANNEL FUNCTIONAL TEST each time the plant is in COLD SHUTDOWN for a period of more than 24 hours, unless performed within the previous 6 months. LD.1 and LE.1

SR 3.3.8.3.2
SR 3.3.8.3.3

b. At least once per 18 months by demonstrating the OPERABILITY of overvoltage, undervoltage and underfrequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic and output circuit breakers and verifying the following setpoints. 24 L.4

SR 3.3.8.3.2

1. Overvoltage Bus A: ≤ 128.0 volts AC (130.5)
   Bus B: ≤ 130.0 volts AC (131.7)
2. Undervoltage Bus A: ≥ 118.5 volts AC (113.6)
   Bus B: ≥ 120.1 volts AC (113.0)
3. Underfrequency ≥ 57 Hz (57.5)

with time delay set to ≤ 4 seconds

M.2

M.3

Page 1 of 1

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Not used.

M.2 Time delay setting requirements have been added in proposed SR 3.3.8.3.2 for the overvoltage, undervoltage, and underfrequency protective devices of the RPS scram solenoid electrical protection assemblies. Currently, no maximum setting is provided in CTS 4.8.4.5.b. These devices have adjustable time delay settings. The new Allowable Value for all protective devices is ≤ 4 seconds. The Allowable Values are based on the current setpoint methodology and ensure that the devices trip to protect the RPS scram solenoids. These Allowable Values are also consistent with the current settings of the devices. This change is an additional restriction on plant operation.

M.3 The underfrequency setpoint currently specified in CTS 4.8.4.5.b.3 is actually the Analytical Limit. Thus, NMP2 can currently continue to call the underfrequency trip Operable as long as the actual setpoint is greater than or equal to the Analytical Limit. NMP2 is currently maintaining the actual setpoint in accordance with the most recent setpoint calculation, to ensure the analytical limit is not exceeded. Proposed SR 3.3.8.3.2 includes the Allowable Value from this setpoint calculation, not the Analytical Limit. This is an additional restriction on plant operation since NMP2 will now be required to maintain the actual setpoint greater than or equal to the Allowable Value. This will ensure the RPS logic buses are providing ≥ 57 Hz to all equipment powered from the buses. The Bases of the ITS also provides this description.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LD.1 The Frequency for performing the system functional test of CTS 4.8.4.5.b has been extended from 18 months to 24 months in proposed SR 3.3.8.3.3. This SR ensures that RPS Electric Power Monitoring Instrumentation (scram solenoids) will function as designed to ensure proper response during an analyzed event. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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: The monitoring logic has been recently modified to implement highly reliable solid state sensing

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) relays. Reviews of historical maintenance and surveillance data for the balance of the system 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 small. RPS Electric Power Monitoring channels may be tested on a more frequent basis during the operating cycle in accordance with (proposed SR 3.3.8.3.1). The testing of the RPS Electric Power Monitoring instrumentation, if performed, ensures that a significant portion of the RPS Electric Power Monitoring instrumentation circuitry is operating properly and will detect significant failures of this circuitry. If this testing is not performed, this change is still considered acceptable based on the historical data and since the RPS Electric Monitoring instrumentation is designed to be single failure proof and therefore, is highly reliable. Based on the modification and the inherent system and component reliability and the testing performed during the operating cycle, the impact, if any, from this change on system availability is small. The review of historical surveillance data also demonstrated that there are no failures that would invalidate this conclusion. 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.

LE.1 The Frequency for performing the CHANNEL CALIBRATION requirement of CTS 3.4.8.4.5.b has been extended from 18 months to 24 months in proposed SR 3.3.8.3.2. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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. Extending the SR Frequency is acceptable because the RPS Electric Power Monitoring instrumentation is designed to be highly reliable. Furthermore the impacted RPS Electric Power Monitoring instrumentation has been evaluated based on make, manufacturer and model number as compared to similar operating equipment with similar operating characteristics to determine the instrumentation's projected drift values. The following paragraphs, listed by CTS function number, identify by make, manufacturer and model number the drift evaluations performed:

TECHNICAL CHANGES - LESS RESTRICTIVE

LE.1 (cont'd)

1. Overvoltage

This function is performed by a Nuclear Logistics Model No. 411U6175-HF-L relay. The Nuclear Logistics relays were evaluated by quantitative analysis and the results indicate the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

2. Undervoltage

This function is performed by a Nuclear Logistics Model No. 411U6175-HF-L relay. The Nuclear Logistics relays were evaluated by quantitative analysis and the results indicate the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

3. Underfrequency

This function is performed by a Nuclear Logistics Model No. 422B1275-L relay. The Nuclear Logistics relays were evaluated by quantitative analysis and the results indicate the projected 30 month drift values for the instruments do not exceed the design allowance provided for these instruments. The results of the analysis support a 24 month fuel cycle surveillance interval extension.

Based on the design of the instrumentation and the drift evaluations, it is concluded that the impact, if any, on system availability is minimal as a result of the change in the surveillance test interval.

A review of the surveillance test history was performed to validate the above conclusion. This review of the surveillance test history, demonstrates that there are no failures that would invalidate the conclusion that the impact, if any on system availability is minimal from a change to a 24-month surveillance frequency. 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.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 CTS 3.8.4.5 requires the RPS scram solenoid bus EPAs to be OPERABLE at all times. The Applicability of ITS 3.3.8.3 is specified as MODE 1 and 2, and MODE 5 with any control withdrawn from a core cell containing one or more fuel assemblies. With no control rods withdrawn from core cells containing fuel assemblies, there is no need for the RPS scram solenoids to perform their function and therefore, there is no need to require their protection. Therefore, the Applicability has been changed to only include those MODES or Conditions when the RPS scram solenoids are required. In addition, ITS 3.10.3 and ITS 3.10.4 will allow a single control rod to be withdrawn in MODES 3 and 4, respectively, by allowing the Reactor Mode Switch to be in the Refuel position. Therefore, the RPS Electric Power Monitoring — Scram Solenoids requirements have been included in ITS 3.10.3 and ITS 3.10.4.

L.2 The allowed out of service time of CTS 3.8.4.5 Action b for two inoperable assemblies is extended from 30 minutes to 1 hour in ITS 3.3.8.3 Required Action B.1 to provide sufficient time for the plant personnel to take corrective actions. The time extension for two inoperable assemblies is minimal but necessary to allow consideration of plant conditions, available personnel, and the appropriate actions.

L.3 This change proposes to add a Note to the Surveillance Requirements that will allow a 6 hour delay from entering into the associated Conditions and Required Actions for a channel placed in an inoperable status solely for performance of required Surveillances provided the other RPS electric power monitoring assembly for the associated RPS scram solenoid bus maintains trip capability. The loss of one electric power monitoring assembly is acceptable in this case since only one of the two assemblies is required to trip the associated power supply if power is not maintained within acceptable limits. The short period of time (6 hours) in this condition will have no appreciable impact on risk. Also, upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition must be entered and Required Actions taken.

L.4 The overvoltage and undervoltage setpoints for CTS 4.8.4.5.b.1 and 2 are actually the Trip Setpoints, not the Allowable Values. Proposed SR 3.3.8.3.2 now includes the Allowable Values, consistent with the philosophy of NUREG-1434. These Allowable Values (to be included in Technical Specifications) have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd) Allowable Value selection evaluation used actual NMP2 operating and surveillance trend information to ensure the validity of the evaluation input data. All changes to safety analysis limits, applied in the methodologies, were evaluated and confirmed as ensuring safety analysis licensing acceptance limits are maintained. All design limits, applied in the methodologies, were confirmed as ensuring that applicable design requirements of the associated systems are maintained. The proposed Allowable Values have been established from each design or safety analysis limit by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The use of these methodologies for establishing Allowable Values ensures design or safety analysis limits are not exceeded in the event of transients or accidents and accounts for uncertainties and environmental conditions.

L.5 CTS 3.8.4.5 does not provide any actions if the RPS EPAs are not restored or the associated RPS MG Set or alternate power supply is not removed from service (which de-energizes the associated RPS scram solenoid bus), as required by Actions a and b. Thus, CTS 3.0.3 is required to be entered. However, since CTS 3.0.3 is not applicable in Mode 5, 10 CFR 50.36(c)(2) requires that the licensee notify the NRC if required by 10 CFR 50.72, and an Licensee Event Report (LER) be submitted to the NRC as required by 10 CFR 50.73. In lieu of these two requirements, a new ACTION is provided if the Required Actions of Condition A or B are not met in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. ITS 3.3.8.3 ACTION D requires action to be initiated to fully insert control rods in cells containing one or more fuel assemblies. This action places the reactor in the least reactive condition and ensures the safety function of the RPS instrumentation will not be required.

DISCUSSION OF CHANGES
ITS: SECTION 3.3 - INSTRUMENTATION BASES

The Bases of the current Technical Specifications for this section (pages B 3/4 3-1 through B 3/4 3-8) have been completely replaced by revised Bases that reflect the format and applicable content of the NMP2 ITS Section 3.3, consistent with the BWR Standard Technical Specifications NUREG-1433, Rev. 1 and NUREG-1434, Rev. 1. The revised Bases are as shown in the NMP2 ITS Bases. In addition, pages 3/4 3-6, 3/4 3-20, 3/4 3-21, 3/4 3-39, 3/4 3-74 through 3/4 3-76, 3/4 3-85, and 3/4 3-103, which are blank pages, have been removed. 1 B

Volume 4
Section 3.3; ISTS/JFDs, ISTS Bases/JFDs, and NSHE

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS: 3.3.1.1 - RPS INSTRUMENTATION

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

2. The NMP2 design does not include a direct scram on high reactor vessel water level. Therefore, this Function (ISTS 3.3.1.1 Function 5) and associated ACTION and Surveillances have been deleted. The following requirements have been renumbered, where applicable, to reflect this deletion.

3. The Frequency for performing SR 3.3.1.1.3 has been extended from 7 days to 184 days, consistent with the current licensing basis. Since this new Frequency is now the same as the current 184 day CHANNEL FUNCTIONAL TEST (CFT) Frequency for the APRM Flow Biased Simulated Thermal Power — Upscale Function, this specific Surveillance has been incorporated into the 184 day CFT Surveillance, also consistent with the current licensing basis. (Current NMP2 requirements test this feature as part of a CFT). B B

4. The Frequency for current NUREG SR 3.3.1.1.8 proposed SR 3.3.1.1.7 has been changed from 1000 MWD/T to 1000 effective full power hours consistent with the current NMP2 Licensing Basis.

5. Editorial change made to be consistent with other similar requirements in the ITS or for clarity.

6. The proper NMP2 plant specific nomenclature/value/design requirements have been provided.

7. Note 2 has been added to ISTS SR 3.3.1.1.17 (ITS SR 3.3.1.1.16) to exempt measuring the sensor response times for Functions 3 and 4 (Reactor Vessel Steam Dome Pressure—High and Reactor Vessel Water Level—Low, Level 3 Functions). Deletion of the response time testing for these sensors was evaluated in NEDO-32291, "System Analyses for Elimination of Selected Response Time Testing Requirements," January 1994, and was determined acceptable since other Technical Specification Surveillances (CHANNEL CALIBRATION, CHANNEL FUNCTIONAL TEST, CHANNEL CHECK, and LOGIC SYSTEM FUNCTIONAL TEST) ensure that instrumentation response times are within acceptable limits. These other tests are normally sufficient to identify failure modes or degradation in sensor response time and assure operation of the analyzed instrument loops within acceptable limits. Furthermore, there are no known failure modes that can be detected by response time testing that cannot also be detected by other Technical Specification Surveillances.

   In addition, the NRC Safety Evaluation Report (SER) from B.A. Boger (NRC) to R.A. Pinelli (BWROG), dated December 28, 1994, required that the utility commit to certain additional requirements and state this in the plant specific license amendment.

7. (continued)

NMPC has reviewed these additional requirements and is in full compliance with these additional requirements. ISTS SR 3.3.1.1.17 Note 2 has been renumbered due to the addition of this proposed Note.

In addition, the definition of RPS Response Time states that the time is measured from when the monitored parameter exceeds its RPS trip setpoint. For ITS Table 3.3.1.1-1 Function 9, Turbine Control Valve Fast Closure, Trip Oil Pressure — Low, the response time is measured from the start of turbine control valve fast closure, not when the monitored parameter (the oil pressure sensor) exceeds its trip setpoint. This is annotated in USAR Table 7.2-3. This allowance was in the RPS Response Time Table in CTS prior to the removal of the Table from the CTS and relocation to the USAR. Therefore, Note 4 has been added to ISTS SR 3.3.1.1.17 (ITS SR 3.3.1.1.16) to take an exception to the definition of RPS Response Time for Function 9 and maintain the current allowance. B B B

8. The proper LCO number has been provided.

9. NMP2 recently replaced the APRMs with NUMAC-Power Range Neutron Monitors (PRNM). Therefore, ISTS 3.3.1.1 ACTION B has been modified, ISTS SR 3.3.1.1.5 and ISTS SR 3.3.1.1.14 have been deleted, ISTS SR 3.3.1.1.11, ISTS SR 3.3.1.1.13, and ISTS SR 3.3.1.1.17 have been modified, ITS SR 3.3.1.1.2 has been added, and ITS Table 3.3.1.1-1 Function 2.e has been added to reflect this change. Also, neither a Logic System Functional Test nor an RPS Response Time Test is required to be performed on any APRM Functions except Function 2.e. Therefore, ITS Table 3.3.1.1-1 has been modified accordingly. These changes are consistent with the Current Licensing Basis. In addition, ISTS SR 3.3.1.1.4 originally was for the IRMs and APRMs, and due to this change, it is now only applicable to the IRMs. Therefore, ISTS SR 3.3.1.1.4 and ISTS SR 3.3.1.1.5 (which are the same test at the same Frequency) have been combined into one SR, ITS SR 3.3.1.1.4, and the Note to this SR is modified to state that it is only applicable to Functions 1.a and 1.b (the IRM Functions). The remaining SRs have been renumbered and Table 3.3.1.1-1 modified to reflect these changes.

10. The Frequency for ISTS SR 3.3.1.1.6 has been changed from "Prior to withdrawing SRMs from the fully inserted position" to "Prior to fully withdrawing SRMs." The current licensing basis for NMP2 only requires the SRM/IRM overlap to be verified during a reactor startup. It does not require the overlap verification prior to withdrawing the SRMs from the fully inserted position. The current practice of NMP2 is to maintain the SRMs between 100 cps and 10^5 cps. During the reactor startup, the operating staff will start to withdraw the SRMs prior to the IRMs coming on range. This reduces the burnup of the SRMs. The SRM/IRM overlap is verified before the SRMs are fully withdrawn. In addition, a review of operating data has shown that it may not always be possible to obtain proper overlap prior to reaching

10. (continued)

the SRM rod block setpoint with the SRMs fully inserted. Therefore, ITS SR 3.3.1.1.5 has been modified to reflect the current practice, and is consistent with current licensing basis.

11. The CHANNEL CALIBRATION Frequency for Table 3.3.1.1-1 Function 7.a is being maintained at 18 months, consistent with current licensing basis. Since all other CHANNEL CALIBRATION Frequencies are 24 months, a new 18 month CHANNEL CALIBRATION SR is being added (ITS SR 3.3.1.1.11).

1. Editorial change made to be consistent with other similar requirements in the ITS or for clarity.

2. Function 3.c, the HPCS Reactor Vessel Water Level—High, Level 8 logic is a one-out-of-two taken twice logic. Therefore, to use the 6 hour allowance of Note 2 to the Surveillance Requirements, HPCS initiation capability must be maintained. In addition, the proper ACTION is ACTION B, since HPCS capability must also be maintained to use the 24 hour allowed outage time, and placing the channel in trip is acceptable in lieu of restoring the channel. This is also consistent with the RCIC System Instrumentation actions in the Current Technical Specifications.

3. Twelve new ECCS Functions have been added. ITS Functions 1.a, 1.d, 2.a, and 2.d are closure signals for the RHR A and B heat exchanger sample and RHR B discharge to radwaste valves. These valves are closed to allow full LPCI flow assumed in the accident analysis. These Functions are similar to those Functions that start the LPCI subsystems, since the start signals also close certain RHR valves that can divert flow from the reactor vessel. ACTION B has also been modified to reflect the proper actions for these four new Functions. 1B

   ITS Functions 1.e, 1.f, 1.g, 2.e, 2.f, and 2.g are time delay relays that delay starting of the low pressure ECCS pumps following a LOCA depending upon whether or not offsite power is available. These Functions are similar to those Functions in the ISTS that delay starting ECCS pumps following a LOCA with offsite power not available (ISTS Functions 1.c and 2.c, ITS Functions 1.h and 2.h). NMP2 has a total of eight time delay relay Functions, two for each low pressure ECCS pump. Thus the six new Functions combined with the two in the ISTS (as modified) are consistent with the NMP2 current licensing basis. In addition, ISTS Function 1.d, the Reactor Steam Dome Pressure—Low, (Injection Permissive) provides the signal to open the Division 1 ECCS pumps injection valves. The NMP2 design includes separate Functions for the LPCS and LPCI injection valves. Therefore, ITS Function 1.j has been added for the LPCI injection valve Function. Since these seven new Functions have been added, ITS Note 2 to Required Action C.1 has been modified to include these seven new Functions, consistent with the intent of the ISTS Note 2 to Required Action C.1. 1B 1B 1B

   ITS Function 3.e is the time delay relay that delays shifting the HPCS suction from the CST to the suppression pool on low CST level. The appropriate ACTIONS and Surveillance Requirements have also been added. In addition, since the logic is one-out-of-one, the 6 hour allowance (without maintaining ECCS initiation capability) of ITS Note 2 to the Surveillance Requirements, has been made applicable to this Function.

   In addition, the Functions have been renumbered, where applicable, to reflect these additions.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2.4

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

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

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

SR 3.3.1.2.5 and SR 3.3.1.2.6

Performance of a CHANNEL FUNCTIONAL TEST demonstrates the associated channel will function properly. SR 3.3.1.2.5 is required in MODE 5, and the 7 day Frequency ensures that the channels are OPERABLE while core reactivity changes could be in progress. This 7 day Frequency is reasonable, based on operating experience and on other Surveillances (such as a CHANNEL CHECK) that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

1 in MODES 3 and 4 and core reactivity changes are due only to control rod movement in MODE 2

SR 3.3.1.2.6 is required in MODE 2 with IRMs on Range 2 or below and in MODES 3 and 4. Since core reactivity changes do not normally take place, the Frequency has been extended from 7 days to 31 days. The 31 day Frequency is based on operating experience and on other Surveillances (such as

(continued)

All changes are (1) unless otherwise indicated

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(4) 3.e, 3.f, 3.g, 3.h. Ambient and Differential Area Temperature—High

Ambient and Differential Temperatures are provided to detect a leak from the associated system steam piping. The isolation occurs when a very small leak has occurred and is diverse to the high flow instrumentation. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. These Functions are not assumed in any (1) FSAR transient or accident analysis, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

RCIC

area, two channels for the RCIC steam line tunnel area

Ambient and Differential Temperature—High signals are initiated from thermocouples that are appropriately located to protect the system that is being monitored. Two instruments monitor each area. Six channels for RHR and RCIC Ambient Temperature—High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two for the RCIC room and four for the RHR area.

Area

in the area

Two

each

for each Function

area monitored by the

Channels

equipment room

There are 12 thermocouples (four for the RCIC room and eight for the RHR area) that provide input to the Area Ventilation Differential Temperature—High Function. The output of these thermocouples is used to determine the differential temperature. Each channel consists of a differential temperature instrument that receives inputs from thermocouples that are located in the inlet and outlet of the area cooling system for a total of six (two for the RCIC room and four for the RHR area) available channels.

(two per area), eight channels for the reactor building pipe chase areas (two per area), and 10 channels for the reactor building general areas (two per area).

The Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

The Function isolates the Group valves.

3.g, 3.h. Main Steam Line Tunnel Ambient and Differential Temperature—High

(4) Ambient and Differential Temperature—High is provided to detect a leak in the RCPB and provides diversity to the high flow instrumentation. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite limits may be reached. However, credit for these instruments is not taken in any

(continued)

(1) INSERT 5.a, 5.d, and 5.e

There are four channels for the RHR equipment room areas (two per area), eight channels for the reactor building pipe chase areas (two per area), and 10 channels for the reactor building general areas (two per area). (B)

The Area Temperature — High Functions are only required to be OPERABLE in MODE 3. In MODES 1 and 2, the Reactor Vessel Pressure — High Function and other administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.2 (continued)

The Frequency is based upon the assumption of a 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.2.3

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. FSAR, Section 8.3.1.1.6j.
2. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."
3. 10 CFR 50.36 (c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2 (continued)

The Frequency is based upon the assumption of a 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.3

Performance of a system functional test demonstrates that, with a required system actuation (simulated or actual) signal, the logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. FSAR, Section 8.3.1.1.6.

2. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."

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

Insert Page B.3.3-246i

L.3 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident. B

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most B

L.3 CHANGE

3. (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident. 1B

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most 1B

L.1 CHANGE

3. (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.3.2.2 - FEEDWATER SYSTEM AND MAIN TURBINE HIGH WATER LEVEL TRIP INSTRUMENTATION

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident. 1B

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration 1B

L.1 CHANGE

3. (continued)

uncertainty, instrument uncertainty, environmental effects, and drift. The most conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

L.3 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The change modifies the Channel Check Surveillance to exempt channels that are normally deenergized. The Remote Shutdown System is not considered as an initiator for any accidents previously analyzed accident. Therefore, this change does not significantly increase the probability of a previously analyzed accident. In addition, since the channel is normally deenergized and is not indicating properly, no specific acceptance criteria for the Channel Check applies. That is, performance of the Channel Check with the instrument deenergized is essentially equivalent to not performing the requirement. Therefore, this change does not significantly increase the consequences of a previously analyzed accident.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change does not involve a significant reduction in a margin of safety since the instruments are not required to provide automatic response to any design basis accident. The non performance of a Channel Check on a deenergized instrument does not significantly affect the contribution of the instrument to risk reduction since the instrument is Calibrated properly and its OPERABILITY verified during the calibration.

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident. 1B

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most 1B

L.1 CHANGE

3. (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most

L.1 CHANGE

3. (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.3.5.1 - ECCS INSTRUMENTATION

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident. 1B

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most 1B

L.1 CHANGE

3. (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

L.5 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   This change will allow two channels of a ECCS Instrumentation Function to be inoperable for up to 24 hours, 96 hours, or 8 days (depending upon the Function) prior to placing them in the tripped condition or declaring the associated ECCS inoperable. ECCS actuation logic is not considered as an initiator for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. The channels for the LPCS, LPCI, and ADS Functions are combined in a two-out-of-two logic; thus when one or both channels of a Function are inoperable, the Function will not perform its intended function. For the HPCS Functions, with only one channel per trip system of a Function inoperable, the Function can still perform its intended function. The proposed out of service time has already previously been approved by the NRC for use at NMP2 for one channel inoperable. Therefore, allowing two channels of a LPCS, LPCI, and ADS Function to be inoperable for this proposed time is equivalent to one channel inoperable; in both cases, the Function cannot perform its intended function. Allowing two HPCS channels (one per trip system) of a Function is acceptable since the Function can still perform its intended function. Therefore, this change does not significantly increase the consequences of a previously analyzed accident.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change does not involve a significant reduction in a margin of safety since the overall ECCS safety function continues to provide the required ECCS actuation capability.

L.12 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   This change will provide additional time to restore the Manual Initiation Function of the ADS System. Manual initiation logic is not considered as an initiator for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Also, this change does not further degrade the capability of the ADS System to perform its required automatic function. Therefore, this change does not significantly increase the consequences of a previously analyzed accident.

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

   The proposed change does not introduce a new mode of plant operation and does not involve a physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change does not involve a significant reduction in a margin of safety since the Manual Initiation of the ADS System is not credited in the accident analysis. The additional time is minor, the ability to initiate individual ADS valves or another ECCS System is possible if an event occurs, and is consistent with the time period allowed for other equipment that is not assumed to operate for mitigation of a DBA.

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.3.5.2 - RCIC SYSTEM INSTRUMENTATION

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident. 1B

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most 1B

L.1 CHANGE

3. (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most

L.1 CHANGE

3. (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

L.14 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The change provides the option to declare the SLC System inoperable instead of isolating the RWCU System. The SLC System Initiation Function instrumentation is not assumed to be an initiator of any analyzed event. The role of the instrumentation is to isolate the RWCU System to ensure the SLC System can function properly and the injected boron is not removed from the Reactor Coolant System. The proposed change to the ACTIONS will not allow continuous operation such that the SLC System cannot perform its intended function. Therefore, the proposed change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   No significant reduction in a margin of safety is involved with this change since the proposed alternative actions are identical to those associated with the mechanical Specification (SLC System). Since the instrumentation actuates to ensure the SLC System can perform its intended function, these actions are appropriate and the margin of safety is maintained equivalent of the margin of safety when the SLC System is inoperable.

L.14 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The change provides the option to declare the SLC System inoperable instead of isolating the RWCU System. The SLC System Initiation Function instrumentation is not assumed to be an initiator of any analyzed event. The role of the instrumentation is to isolate the RWCU System to ensure the SLC System can function properly and the injected boron is not removed from the Reactor Coolant System. The proposed change to the ACTIONS will not allow continuous operation such that the SLC System cannot perform its intended function. Therefore, the proposed change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   No significant reduction in a margin of safety is involved with this change since the proposed alternative actions are identical to those associated with the mechanical Specification (SLC System). Since the instrumentation actuates to ensure the SLC System can perform its intended function, these actions are appropriate and the margin of safety is maintained equivalent of the margin of safety when the SLC System is inoperable.

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most

L.1 CHANGE

3. (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident. 1 B

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most 1 B

L.1 CHANGE

3. (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

NO SIGNIFICANT HAZARDS EVALUATION
ITS: 3.3.8.1 - LOSS OF POWER INSTRUMENTATION

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   Trip setpoints are not included in the ITS and all references to these setpoints are deleted. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These trip setpoints are not considered as initiators for any accidents previously analyzed. Therefore, this change does not significantly increase the probability of a previously analyzed accident. Further, this change does not impact the capability of the system to perform its required function since the Allowable Value, which is the required limitation, is still being maintained. Therefore, this change does not significantly increase the consequences of a previously analyzed accident. 1 B

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Trip setpoints have not been included in the ITS. The Allowable Value is the required limitation for the associated Function and this value is retained in the NMP2 ITS. These Allowable Values have been established consistent with the methods described in Regulatory Guide 1.105, Revision 2, February 1986, ISA-S67.04-1982, and/or the General Electric Setpoint Methodology described in NEDC-31336P-A, limited by the NRC Safety Evaluation Report, Revision 1, dated 11/6/95. The Allowable Values are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, and applicable environmental effects. The trip setpoints are derived from the analytical limits by accounting for calibration uncertainty, process measurement uncertainty, primary element uncertainty, instrument uncertainty, applicable environmental effects, and drift. The trip setpoints are also derived from the Allowable Values in the conservative direction by considering calibration uncertainty, instrument uncertainty, environmental effects, and drift. The most 1 B

L.1 CHANGE

3. (continued)

conservatively derived trip setpoints are used. In addition, both the Allowable Values and trip setpoints may have additional conservatisms. Plant calibration procedures will ensure that the assumptions regarding calibration accuracy, measurement and test equipment accuracy, and setting tolerance are maintained. The Bases for the ITS also describes the relationship between the Allowable Value and the trip setpoint. This description is consistent with the NMP2 Instrument Setpoint Methodology. Thus, any changes to the trip setpoints will either be in accordance with the NMP2 Instrument Setpoint Methodology, or if not, then a Bases change, which is controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS, would be required prior to changing the trip setpoint. Therefore, this change does not involve a significant reduction in a margin of safety.

L.5 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The proposed change removes the requirement to notify the NRC if required by 10 CFR 50.72 and to submit a Licensee Event Report as required by 10 CFR 50.73 if the RPS EPAs are not restored to Operable status or the RPS UPS is not removed from service in MODES or other specified conditions other than MODES 1, 2, and 3. It replaces these requirements with specific actions that place the reactor in the least reactive condition and ensures either the safety function of the RPS, primary containment isolation system, secondary containment isolation system, and CREF System will not be required or is already met. An option is also given to continue to restore an assembly to OPERABLE status under certain conditions since there may be a need for RHR SDC System. Alternately, options are also provided under certain conditions to declare the affected components inoperable and take the ACTIONS required by the individual Specifications. The required reports are not assumed to be an initiator of any analyzed event. Therefore, the change does not involve a significant increase in the probability of an accident previously evaluated. The consequences of an accident are not affected by the deletion of these reporting requirements since they do not impact the assumptions of any design basis accident or transient.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   The margin of safety is not reduced by removing the requirement for the submittal of these required reports. This proposed change has no effect on the assumptions of the design basis accident. This change also has no impact on the safe operation of the plant because adequate actions are provided if the RPS EPAs cannot be restored and the RPS UPS cannot be removed from service. This change does not affect any plant equipment or requirements for maintaining plant equipment. Therefore, this change does not involve a significant reduction in a margin of safety.

L.5 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The proposed change removes the requirement to notify the NRC if required by 10 CFR 50.72 and to submit a Licensee Event Report as required by 10 CFR 50.73 if the RPS EPAs are not restored to Operable status or the RPS MG Set or alternate power supply is not removed from service in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. It replaces these requirements with specific actions that place the reactor in the least reactive condition and ensures the safety function of the RPS instrumentation will not be required. The required reports are not assumed to be an initiator of any analyzed event. Therefore, the change does not involve a significant increase in the probability of an accident previously evaluated. The consequences of an accident are not affected by the deletion of these reporting requirements since they do not impact the assumptions of any design basis accident or transient.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   The margin of safety is not reduced by removing the requirement for the submittal of these required reports. This proposed change has no effect on the assumptions of the design basis accident. This change also has no impact on the safe operation of the plant because adequate actions are provided if the RPS EPAs cannot be restored and the RPS MG Set or alternate power supply cannot be removed from service. This change does not affect any plant equipment or requirements for maintaining plant equipment. Therefore, this change does not involve a significant reduction in a margin of safety.

Volume 5
Sections 3.4 and 3.5

Section 3.4

DISCUSSION OF CHANGES
ITS: 3.4.2 - FLOW CONTROL VALVES (FCVs)

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 CTS 4.4.1.1.3 provides Surveillance Requirements for the flow control valves. Since CTS 4.4.1.1.3 is part of the Recirculation Loop Technical Specification, CTS 3/4.4.1.1, it is covered by the LCO of CTS 3.4.1.1 and the Applicability of CTS 3.4.1.1. The ITS provides a separate LCO for the flow control valves, thus a new LCO statement and Applicability statement are needed. However, since they continue to require flow control valve OPERABILITY in the same MODES as CTS 3/4.4.1.1, the addition of the new LCO and Applicability are administrative. ITS 3.4.2 ACTION A allows 4 hours to lock up the flow control valve if it is inoperable. This time is consistent with the time in CTS 3.4.1.1 Action a when a loop is not in operation. The actual proposed action (lock up the flow control valve) is the acceptance criteria to which the flow control valve is tested by the current Surveillance (CTS 4.4.1.1.3). Thus placing the flow control valve in this position performs the safety function of the flow control valve. The proposed change will provide only additional clarification of the current requirements, and is therefore considered administrative. B

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LD.1 The Frequencies for performing CTS 4.4.1.1.3.a and 4.4.1.1.3.b (proposed SRs 3.4.2.1 and 3.4.2.2) have been extended from 18 months to 24 months. These SRs ensure that FCVs fail "as is" on loss of hydraulic pressure at the hydraulic control unit and that the average rate of FCV movement is within the

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd)

specific limit (≤ 11%/sec). The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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. 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 is small.

During normal operation, the FCVs are slowly positioned to obtain the required core flow and power conditions. If an actual or false signal is present requiring a Motion Inhibit (position setpoint demand signal exceed limits, large velocity controller deviation for more than a preset time, and high drywell pressure), the associated FCV should lock up. Therefore, during normal plant operations, the system is utilized and major deviations will not go unnoticed. If any inconsistencies are observed during FCV movement, the flow control system or the hydraulic control units may be taken out of service to perform the required maintenance. After repair, the system may be tested during plant operation to ensure the FCVs function properly.

If a DBA LOCA were to occur, drywell pressure will increase. Drywell pressure sensors will detect this pressurization and immediately drop hydraulic pressure to the pilot lines of check valves on the FCV actuators. These pressure sensors are environmentally qualified for LOCA and post-LOCA conditions. With loss of pilot pressure, the check valves will close and lock up the FCV. Until these interlocks are cleared, no control system signal (intentional or inadvertent) can cause FCV position to change. Failure Modes and Effects Analysis have shown that, given a LOCA event, no single failure in the electronic/hydraulic controls can cause the FCV to close. As a result of these considerations, FCV closure in the unbroken loop is not expected to occur during the LOCA event.

Even if the FCVs were signaled to close for some unlikely reason (LOCA plus two failures: failure of drywell high pressure signal such that FCV lockup does not occur, and failure of FCV controls), backup electronic velocity limiters are included in the recirculation control system to limit FCV velocity to 11%/sec. Additional multiple specific component failures in these limiters must occur to cause full closure of the FCV at velocities in excess of this value. The combined probability of occurrence of these specific failure modes during a

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) LOCA is less than or 10E-6 per year. Accordingly, the electronically limited rate of less than or equal to 11% of FCV actuator stroke rate is considered a realistic yet conservative closure rate.

The velocity limiters are also available to minimize the consequences of the Reactor Recirculation Flow Runout and Flow Control Failure (decreasing flow) transients ensuring the FCVs either open or close at a rate less than or equal to 11%/sec which is assumed in the analysis. In these transients the analysis assumes the FCVs both move at a velocity of ± 11%/sec. The probability of this type of failure is very small since NMP2 normally positions the flow controllers in manual and in this condition the control signal of each loop is independent of each other. Now in the case of transients involving the failure of one FCV, the analysis assumes an FCV moves at a velocity of 30%/sec in the opening direction and 60%/sec in the closing direction. In these transients, the velocity limiters are available to limit the FCV velocity to ± 11%/sec and in addition the hydraulic system is designed to limit the FCV velocity to +30%/sec and -60%/sec, which is within the values assumed in the transient analysis.

Based on the Reactor Recirculation System design and the ability to detect deviations during operation, it is shown that the impact, if any, on system availability is small as a result of the change.

The review of historical surveillance data also demonstrated that there are no failures that would invalidate the conclusion that the impact, if any, on system availability is small from a change to CTS 4.4.1.1.3.a and 4.4.1.1.3.b as implemented in SRs 3.4.2.1 and 3.4.2.2. In addition, the proposed 24-month Surveillance Frequency, if performed at the maximum interval by proposed SR 3.0.2 (30 months), does not invalidate any assumptions in the plant licensing basis.

"Specific"

None

A.1

Specification 3.4.5

REACTOR COOLANT SYSTEM

REACTOR COOLANT SYSTEM LEAKAGE

OPERATIONAL LEAKAGE

LIMITING CONDITIONS FOR OPERATION

A.3

e. With one or more of the required interlocks shown in Table 3.4.3.2-3 inoperable, restore the inoperable interlock to OPERABLE status within 7 days or isolate the affected heat exchanger(s) from the RCIC steam supply by closing and deenergizing heat exchanger valves 2RHS*MOV22A and 2RHS*MOV80A or 2RHS*MOV22B and 2RHS*MOV80B, as appropriate.

moved to LCO 3.4.6

A.4

ACTION B

ACTION C

f. With any reactor coolant system leakage greater than the limit in 3.4.3.2.e above, identify the source of leakage or reduce the leakage to within limit within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1 4.4.3.2.1 The RCS leakage shall be demonstrated to be within each of the above limits by:

L.A.1

a. Monitoring the primary containment airborne particulate radioactivity at least once per 12 hours,

b. Monitoring the drywell floor drain tank and equipment drain tank fill rate at least once per 12 hours,

L.1

c. Monitoring the primary containment airborne gaseous radioactivity at least once per 12 hours, and

L.2

d. Monitoring the reactor vessel head flange leak detection system at least once per 24 hours.

4.4.3.2.2 Each RCS pressure isolation valve specified in Table 3.4.3.2-1 shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5, using the method and acceptance criteria specified in the Inservice Testing Program, and verifying the leakage of each valve to be within the specified limit:

B

a. At least once per 18 months, and
b. Before returning the valve to service following maintenance, repair, or replacement work on the valve.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

A.3 moved to LCO 3.4.6

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Details of the CTS 4.4.3.2.1 methods for performing the reactor coolant system leakage Surveillance (by monitoring the primary containment airborne particulate and gaseous radioactivity and by monitoring the drywell floor drain tank and equipment drain tank fill rate) are proposed to be relocated to the Bases. The requirements of proposed SR 3.4.5.1 are adequate to determine reactor coolant system leakage is within required limits. As a result, the details relocated to the Bases are not necessary for ensuring reactor coolant system leakage is determined and do not need 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"

L.1 The Surveillance Frequency for CTS 4.4.3.2.1.b (proposed SR 3.4.5.1), has been changed from 8 hours to 12 hours, consistent with the allowance in Generic Letter 88-01, Supplement 1. The supplement allows the Frequency to be extended to once per shift, not to exceed 12 hours. NMP2 currently has a 12 hour operating shift, thus, the Frequency is adjusted to coincide with this. This is also consistent with the CTS Frequency for monitoring the airborne monitors.

L.2 The reactor vessel head flange leak detection instrumentation in CTS 4.4.3.2.1 does not necessarily relate directly to the LEAKAGE requirements. The reactor vessel head leak detection system monitors the pressure between the inner and outer reactor vessel head seal ring. If the inner seal fails, the instrumentation will annunciate an alarm. The plant can continue to operate with the outer seal performing the required function and the inner seal can be repaired at the next refueling outage. If both seals fail, this can be detected by the Leakage Detection Systems required by CTS 3.4.3.1 and by an increase in drywell temperature and pressure. The instrumentation does not detect nor quantify leakage from the reactor to the containment atmosphere; it does not monitor any leakage controlled by CTS 3.4.3.2. Monitoring overall unidentified leakage is performed by the drywell floor drain tank fill rate monitoring system and the drywell atmospheric monitoring system. Neither the BWR Standard Technical Specifications, NUREG-1434, Revision 1, nor the current NMP2 TS specifies this indication to be OPERABLE in the leakage detection instrumentation Specification (CTS 3/4.4.3.1 and ITS 3.4.7), thus it is not needed to support this Specification. Control of the availability of, and necessary compensatory activities if not available, for indications and monitoring instruments are addressed by plant operational procedures and

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) policies. The requirement to demonstrate LEAKAGE is within limits is still maintained in proposed SR 3.4.5.1. Therefore, this instrumentation, along with the supporting Surveillance is proposed to be deleted from the Technical Specifications.

A.1

Specification 3.4.6

REACTOR COOLANT SYSTEM

REACTOR COOLANT SYSTEM LEAKAGE

OPERATIONAL LEAKAGE

LIMITING CONDITIONS FOR OPERATION

LC.1

e. With one or more of the required interlocks shown in Table 3.4.3.2-3 inoperable, restore the inoperable interlock to OPERABLE status within 7 days or isolate the affected heat exchanger(s) from the RCIC steam supply by closing and deenergizing heat exchanger valves 2RHS*MOV22A and 2RHS*MOV80A or 2RHS*MOV22B and 2RHS*MOV80B, as appropriate.

f. With any reactor coolant system leakage greater than the limit in 3.4.3.2.e above, identify the source of leakage within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The RCS leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment airborne particulate radioactivity at least once per 12 hours,

b. Monitoring the drywell floor drain tank and equipment drain tank fill rate at least once per 8 hours,

c. Monitoring the primary containment airborne gaseous radioactivity at least once per 12 hours, and

d. Monitoring the reactor vessel head flange leak detection system at least once per 24 hours.

SR3.4.6.1 4.4.3.2.2 Each RCS pressure isolation valve specified in Table 3.4.3.2-1 shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5, using the method and acceptance criteria specified in the Inservice Testing Program, and verifying the leakage of each valve to be within the specified limit: LA.1 B

a. At least once per 18 months, and LA.2

b. Before returning the valve to service following maintenance, repair, or replacement work on the valve. L.3

SR3.4.6.1 Note The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

(See Discussion of Changes for ITS: 3.4.5, in this Section)

B

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ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 The ITS 3.4.6 ACTIONS include two Notes not currently provided in the CTS. The first Note to the ACTIONS ("Separate Condition entry is allowed for each flow path") provides explicit instructions for proper application of the ACTIONS for Technical Specification compliance. In conjunction with the proposed Specification 1.3 - "Completion Times," this Note provides direction consistent with the intent of the existing ACTIONS for inoperable PIVs. The second Note to the ACTIONS ("Enter applicable Conditions and Required Actions for systems made inoperable by PIVs") facilitates the use and understanding of the intent to consider any system affected by inoperable PIVs, which is to have its ACTIONS also apply if it is determined to be inoperable. With the ITS LCO 3.0.6, this intent would not necessarily apply. This clarification is consistent with the intent and interpretation of the existing Technical Specifications, and is therefore considered an administrative presentation preference.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The list of pressure isolation valves (PIVs) in CTS Table 3.4.3.2-1 are proposed to be relocated to the Technical Requirements Manual (TRM). The listing of valves which are subject to the RCS PIV Leakage Specification are related to design and are not necessary for ensuring PIV leakage is maintained within limits. ITS 3.4.6 requires the leakage from each RCS PIV to be within limits. These requirements are adequate for ensuring PIV leakage is maintained

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) within limits for the required valves. Therefore, the relocated list is not required to be in the ITS to provide adequate protection of the public health and safety. This change is also consistent with Generic Letter 91-08, which allowed lists of components to be relocated to plant controlled documents. The TRM will be incorporated by reference into the USAR at ITS implementation. Changes to the TRM will be controlled by the provisions of 10 CFR 50.59. In addition to this relocation, all references to the Table in CTS 3.4.3.2.d and 4.4.3.2.2 have been deleted. The Bases identifies that the list of PIVs are located in the TRM.

LA.2 Details of the first Frequency for performing CTS 4.4.3.2.2 are proposed to be relocated to the Inservice Testing (IST) Program (covered by CTS 4.0.5). The requirement to leak test each PIV "At least once per 18 months" is not required to be in Technical Specifications to assure the PIVs are leak tested at least once per 18 months since the IST Program, required by 10 CFR 50.55a, provides 18 month or less leak test requirements for these valves. Compliance with 10 CFR 50.55a, and as a result the IST Program, is required by the NMP2 Operating License. These controls are adequate to ensure the required leak rate testing of PIVs is performed and do not need to be in the ITS to provide adequate protection of the public health and safety. Changes to the IST Program will be controlled by the provisions of the proposed IST Program in Chapter 5 of the ITS.

LC.1 The requirements of CTS 3.4.3.2 ACTIONS d and e, 4.4.3.2.3, and 4.4.3.2.4 concerning high/low pressure interface valve leakage pressure monitors and interlocks do not necessarily relate directly to the leakage limit requirements of the RCS PIVs. The BWR Standard Technical Specifications, NUREG-1434, Rev. 1, does not specify indication-only or alarm-only equipment to be OPERABLE to support OPERABILITY of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indications and monitoring instrumentation are addressed by plant operational procedures and policies. In addition, the leakage limit requirements of ITS 3.4.6 and the leakage test requirements of SR 3.4.6.1 will ensure that the limits will be maintained or the appropriate ACTIONS will be taken. As such, the relocated requirements are not required to be in the ITS to provide adequate protection of the public health and safety. Therefore, this instrumentation, along with the supporting ACTIONS and Surveillances, is proposed to be relocated to the Technical Requirements Manual (TRM). The TRM will be incorporated by reference into the USAR at ITS implementation. Changes to the TRM will be controlled by the provisions of 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 CTS 3.4.3.1 requires the primary containment atmospheric particulate and gaseous radioactivity monitoring systems, and the drywell floor and equipment drain tank fill rate monitoring systems. The required systems are rearranged in ITS 3.4.7 to require one method which can quantify the unidentified LEAKAGE and a diverse detection method which provides only indication of increased leakage.

The drywell equipment drain tank fill rate monitoring system required by CTS 3.4.3.1.d functions to quantify identified leakage. Since the purpose of ITS 3.4.7 is to provide early indication of unidentified RCS leakage, the drywell equipment drain tank fill rate monitoring system requirements specified in CTS 3.4.3.1.d and Action b, as well as Action d, which allows both the equipment and floor drain tank fill rate monitoring systems to be inoperable, have been deleted. ITS 3.4.5 will continue to require that identified leakage (as part of the total leakage limit) be quantified. However, the ITS will not specifically place a Technical Specification requirement on the actual method used to quantify identified leakage. A diverse method to quantify increased leakage is still provided by the drywell floor drain tank fill rate monitoring system, and this is the primary method for quantifying unidentified leakage. In addition, CTS 4.4.3.1.b has also been modified to only require the "drywell floor drain tank fill rate monitoring system" (proposed SR 3.4.7.3) to be tested to reflect these new requirements. B

The drywell atmospheric particulate and gaseous monitoring system in CTS 3.4.3.1.a and b are grouped so that only one of the two is required in ITS LCO 3.4.7.b, instead of the current requirement that both systems be OPERABLE, since they provide the same type of indication. A diverse method to quantify increased leakage is still provided by the drywell floor drain tank fill rate monitoring system, and this is the primary method for quantifying unidentified leakage. CTS 3.4.3.1 Action a, which allows only one of the two atmospheric monitoring systems to be inoperable, has been modified in ITS 3.4.7 ACTION B to allow the "required" atmospheric monitoring system, i.e., both particulate and gaseous monitors, to be inoperable for 30 days, consistent with the new requirement in ITS LCO 3.4.7.b that only one of these two monitors be OPERABLE. In addition, CTS 4.4.3.1.a has also been modified to only require the "required" drywell atmospheric monitoring system (proposed SR 3.4.7.1 and SR 3.4.7.2) and the "required" leakage detection instrumentation (proposed SR 3.4.7.4) to be tested to reflect these new requirements.

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) Therefore, since two diverse methods are still being maintained to detect unidentified leakage and identified and unidentified leakage is still required to be quantified, this change, which is consistent with the BWR/6 ISTS, is considered acceptable. B

L.2 Currently, CTS 3.0.4 would preclude a change in MODES with leakage detection monitoring system inoperable. A statement that LCO 3.0.4 is not applicable for the condition of the drywell floor drain tank fill rate monitoring system inoperable or the required drywell atmospheric monitoring system inoperable has been added as a Note to ITS 3.4.7 ACTION A and ACTION B. When this allowance is used, either the drywell floor drain tank fill rate monitoring system or the required drywell atmospheric monitoring system remains available, and the compensatory actions for the inoperable system (or the requirement that unidentified leakage be quantified in accordance with ITS 3.4.5) will provide adequate indication of RCS leakage. Since 1) probabilities have determined a 30 day allowed out of service time for one leakage detection system is acceptable; 2) a leakage detection system is still OPERABLE; and 3) compensatory measures will still ensure leakage is being quantified, the LCO 3.0.4 exception is considered to provide no significant impact on safety and is acceptable.

L.3 A Note has been added to CTS 4.4.3.1.a (Note to ITS 3.4.7 Surveillance Requirements) to allow a channel to be inoperable for up to 6 hours solely for performance of required Surveillances provided the other Leakage Detection System channel is OPERABLE. The 6 hour testing allowance has been granted by the NRC in Technical Specification amendments for Georgia Power Company's Hatch Unit 1 (Amendment 185) and Unit 2 (Amendment 125) and in the ITS amendment for Washington Public Power Supply System Unit 2 (Amendment 149). The NRC has also granted this allowance in other topical reports for the Reactor Protection System, Emergency Core Cooling System, and Isolation System Instrumentation. The 6 hour testing allowance does not significantly reduce the probability of properly monitoring leakage since the other channel must be OPERABLE for this allowance to be used.

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 CTS 3.4.5 Action c requires increased sampling under certain conditions (as specified in CTS Table 4.4.5-1, Item 4.b), when the LCO 3.4.5.a limit is exceeded. (As described in CTS 3.0.1, the Action is only required when the LCO is not met.) CTS Table 4.4.5-1, Item 4.b requires the sampling and analysis once between 2 and 6 hours after the special conditions specified in Action c are met. However, CTS 3.4.5 Action b (ITS 3.4.8, Required Actions A.1 and B.1), which is also required to be taken when the LCO 3.4.5.a limit is not met, already requires the same sampling to be performed every 4 hours at all times when the LCO 3.4.5.a limit is not met, not just when the special conditions specified in Action c are met. Thus, the sampling and analysis requirements of CTS 3.4.5 Action c is redundant to the sampling and analysis requirements of CTS 3.4.5 Action b. Therefore, CTS 3.4.5 Action c has been deleted and its deletion is administrative. B

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 This proposed change modifies CTS Table 4.4.5-1, Item 2 (proposed SR 3.4.8.1), to change the Frequency for isotopic analysis for dose equivalent I-131 concentration from at least once per 31 days to at least once per 7 days. The increased Frequency provides a compensatory measure for ensuring that even with deletion of the requirement that gross specific activity remain less than or equal to 100/E-bar μCi/gram, offsite doses will remain within a small fraction of the limits of 10 CFR 100. This change is more restrictive on plant operations.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The CTS Table 4.4.5-1, Item 5, requires an isotopic analysis of an offgas sample, including quantitative measurements for xenon and krypton. The offgas isotopic analysis for xenon and krypton are not direct measurements related to the limits of ITS 3.4.8. These analyses are used to routinely monitor and trend coolant activity and are applicable to plant specific controls and administrative limits only. Therefore, this Surveillance is proposed to be relocated to the Technical Requirements Manual (TRM). The requirements of proposed SR 3.4.8.1 provide adequate assurance that RCS specific activity will be maintained within required limits. As a result, the additional analysis requirements for xenon and krypton are not necessary for assuring RCS specific activity is within required limits do not need to be in the ITS to provide adequate protection of the public health and safety. The TRM will be incorporated by reference into the USAR at ITS implementation. Changes to TRM will be controlled by the provisions of 10 CFR 50.59.

"Specific"

L.1 The CTS LCO 3.4.5.b requirement to maintain specific activity ≤ 100/E-bar μCi/gm has been deleted. The current Bases state that the intent of the requirement to limit the specific activity of the reactor coolant is to ensure that whole body and thyroid doses at the site boundary would not exceed a small fraction of the 10 CFR 100 limits (i.e., 10% of 25 rem and 300 rem, respectively) in the limiting event of a main steam line failure outside containment. To ensure that offsite thyroid doses do not exceed 30 rem, reactor coolant DOSE EQUIVALENT I-131 (DEI) is limited to less than or equal to 0.2 μCi/gm. Current Technical Specifications also limit reactor coolant gross specific activity to less than or equal to 100/E-bar μCi/gm to ensure that whole body doses do not exceed 2.5 rem.

CTS 3.11.2.7 (ITS 3.7.4) associated with radioactive effluents requires that the gross gamma radioactivity rate of the noble gases Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88 measured at the Offgas System pretreatment monitor station be limited to less than or equal to 350 mCi/second. The current Bases for CTS 3.11.2.7 state that restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total-body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the 10 CFR 100 limits in the event this effluent is inadvertently discharged without treatment directly to the environment.

The Offgas System, as required by CTS 3.11.2.7 and ITS 3.7.4, provides reasonable assurance the reactor coolant gross specific activity is maintained at

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) a sufficiently low level to preclude offsite doses from exceeding a small fraction of the 10 CFR 100 limits in the event of a main steam line failure. Therefore, CTS 3.4.5.b is redundant and places an unnecessary burden on the licensee without a commensurate increase in the margin of safety. Elimination of CTS 3.4.5.b will allow plant personnel to focus attention on efficient, safe operation of the plant without the unnecessary distraction of the redundant Surveillance Requirement. Additional assurance that the offsite doses will not exceed a small fraction of the 10 CFR 100 limits is provided by increasing the frequency of sampling and analysis of the reactor coolant for DEI from at least once per 31 days to at least once per 7 days, (see comment M.1). Since (1) the reactor coolant limit on DEI adequately assures that offsite doses will not exceed small fractions of the 10 CFR 100 limits in the event of a main steam line failure outside containment and (2) gross gamma radioactivity rate of the noble gases measured at the Offgas System pretreatment monitor station is limited by ITS 3.7.4 to a value that provides reasonable assurance the reactor coolant gross specific activity is maintained at a sufficiently low level to preclude offsite doses from exceeding a small fraction of the 10 CFR 100 limits, the requirements associated with CTS 3.4.5.b are unnecessary. The associated ACTIONS and Surveillance Requirements are also being deleted, consistent with the LCO requirement deletion.

L.2 The Applicability of CTS 3.4.5 (including Table 4.4.5-1 measurement 4) is Operating Conditions 1, 2, 3, and 4. In ITS 3.4.8, the Applicability is proposed to be limited to those conditions which represent a potential for release of significant quantities of radioactive coolant to the environment. MODE 4 is omitted since the reactor is not pressurized and the potential for leakage is significantly reduced. In MODES 2 and 3, with the main steam lines isolated, no escape path exists for significant releases and requirements for limiting the specific activity are not required. CTS 3.4.5 Actions a and b (ITS 3.4.8, ACTIONS A and B) are also modified to reflect the new Applicability, and an option for exiting the applicable MODES is provided for cases where isolation is not desired (ITS 3.4.5 Required Actions B.2.2.1 and B.2.2.2).

L.3 Currently, MODE changes are precluded by CTS 3.0.4 if the limit of CTS 3.4.5.a is not met. A Note is added to CTS 3.4.5 Action a (ITS 3.4.8 ACTION A) to indicate that LCO 3.0.4 is not applicable during the first 48 hours of failure to meet the LCO limit provided the specific activity is $\leq$ 4.0 μCi/gm DEI. Entry into the applicable MODES should not be restricted since the most likely response to the condition is restoration of compliance within the allowed 48 hours. Further, since the LCO limits assure the dose due to a MSLB would be a small fraction of the 10 CFR 100 limits, operation during the allowed time frame would not represent a significant impact to the health and safety of the public.

Specification 3.4.9

A.1

REACTOR COOLANT SYSTEM

3/4.4.9 RESIDUAL HEAT REMOVAL

HOT SHUTDOWN

LIMITING CONDITIONS FOR OPERATION

LCO 3.4.9 3.4.9.1 Two* shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and, unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation**, † with each loop consisting of at least: A.2 moved to LCO 3.10.1

a. One OPERABLE RHR pump, and
b. One OPERABLE RHR heat exchanger. LA.1

APPLICABILITY: OPERATIONAL CONDITION 3, with reactor vessel pressure less than the RHR cut-in permissive setpoint.

add proposed ACTIONS NOTE 1 L.1

ACTION: add proposed ACTIONS NOTE 2 A.3

ACTION A a. With less than the above required RHR shutdown cooling mode loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible. Within 1 hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop. Be in at least COLD SHUTDOWN within 24 hours.†† A.4 A.5

ACTION B b. With no RHR shutdown cooling mode loop or recirculation loop in operation, immediately initiate corrective action to return at least one loop to operation as soon as possible. Within 1 hour, establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour. A.6

add proposed SR 3.4.9.1 Note L.1

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1 4.4.9.1 At least one shutdown cooling mode loop of the residual heat removal system or alternative method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours. or recirculation loop A.6 Required Action B.2 LA.2

LCO Note 2* One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation. L.2

LCO Note 1** The shutdown cooling pump may be removed from operation for up to 2 hours per 8-hour period provided the other loop is OPERABLE.

† The RHR shutdown cooling mode loop may be removed from operation during hydrostatic and system leakage testing. A.2 moved to LCO 3.10.1 B

†† Whenever two or more RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods. A.5

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A.1

Specification 3.4.10

REACTOR COOLANT SYSTEM

RESIDUAL HEAT REMOVAL

COLD SHUTDOWN

LIMITING CONDITIONS FOR OPERATION

LCO 3.4.10 3.4.9.2 Two* shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and, unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation** † ~~with each loop consisting of at least:~~ A.2 moved to LCO 3.10.1

~~a. One OPERABLE RHR pump, and~~
~~b. One OPERABLE RHR heat exchanger.~~ LA 1

APPLICABILITY: OPERATIONAL CONDITION 4.

ACTION: Add proposed ACTIONS NOTE A.3

ACTION A a. With less than the above required RHR shutdown cooling mode loops OPERABLE, within 1 hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop.

ACTION B b. With no RHR shutdown cooling mode loop or recirculation loop in operation, within 1 hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour. A.4

SURVEILLANCE REQUIREMENTS or recirculation loop A.4

SR 3.4.10.1 4.4.9.2 At least one shutdown cooling mode loop of the residual heat removal system or alternative method shall be determined to be in operation ~~and circulating reactor coolant~~ at least once per 12 hours. LA.2

Required Action B.1

LCO NOTE * 2 One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing ~~provided the other loop is OPERABLE and in operation.~~ L.1

LCO NOTE ** 1 The shutdown cooling pump may be removed from operation for up to 2 hours every 8-hour period ~~provided the other loop is OPERABLE.~~ A.2

† The shutdown cooling mode loop may be removed from operation during hydrostatic and system leakage testing. B

Moved to LCO 3.10.1

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A.1

REACTOR COOLANT SYSTEM

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

Specification 3.4.11

LIMITING CONDITIONS FOR OPERATION

LCO 3.4.11 3.4.6.1 The reactor coolant system temperature and pressure shall be limited in accordance with the limit lines shown on Figure 3.4.6.1-1 for hydrostatic or system leakage testing. Figure 3.4.6.1-2 for heatup by non-nuclear means. Figure 3.4.6.1-3 for cooldown following a nuclear shutdown and low-power PHYSICS TESTS; and Figures 3.4.6.1-4 and 3.4.6.1-5 for operations with a critical core other than low-power PHYSICS TESTS, with:

(within limits) A.1

SR 3.4.11.1 SR 3.4.11.2

1 B

a. A maximum heatup of 100°F in any 1-hour period,

SR 3.4.11.1

b. A maximum cooldown of 100°F in any 1-hour period,

c. A maximum temperature change of less than or equal to 20°F in any 1-hour period during hydrostatic and system leakage testing operations above the heatup and cooldown limit curves, and 1 B

SR 3.4.11.7 SR 3.4.11.8 SR 3.4.11.9

d. The reactor vessel flange and head flange temperature greater than or equal to 70°F when reactor vessel head bolting studs are under tension.

APPLICABILITY: At all times. A.2

ACTION: (add proposed Conditions A and C Notes) A.3

ACTIONS A and C

With any of the above limits exceeded, restore the temperature and/or pressure to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system; determine that the reactor coolant system remains acceptable for continued operations; or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours. M.1

ACTION B

(add proposed Required Actions A.2 and C.2 Completion Times)

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1 4.4.6.1.1 During system heatup, cooldown, and system leakage and hydrostatic testing operations, the reactor coolant system temperature and pressure shall be determined to be within the above required heatup and cooldown limits ~~and to the right of the limit lines~~ of Figures 3.4.6.1-1, 3.4.6.1-2, 3.4.6.1-3, 3.4.6.1-4, and 3.4.6.1-5 as applicable, at least once per 30 minutes. 1 B LA.1

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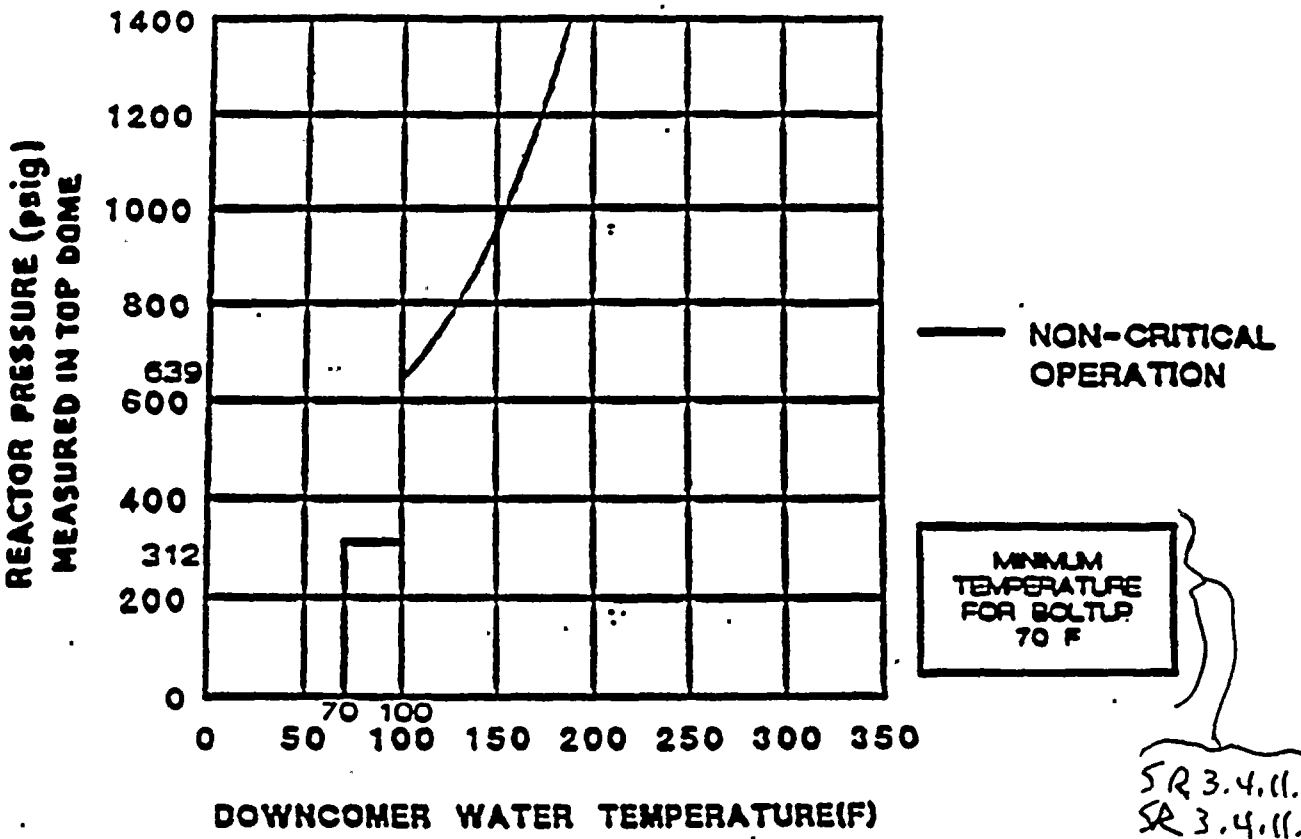
A.1

Specification 3.4.11

Figure 3.4.11-1

NINE MILE POINT UNIT 2

NON-CRITICAL HYDROTEST



SR 3.4.11.7
SR 3.4.11.8
SR 3.4.11.9

FIGURE 3.4.6.1-1 MINIMUM BELTLINE DOWNCOMER WATER TEMPERATURE FOR PRESSURIZATION DURING HYDROSTATIC TESTING AND SYSTEM LEAKAGE TESTING (REACTOR NOT CRITICAL) FOR UP TO 12.8 EFFECTIVE FULL POWER YEARS OF OPERATION

B

A.1

1 B

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The ACTION of CTS 3.4.6.1 does not specify a Completion Time for completion of the engineering evaluation. A specific Completion Time for the engineering evaluation and determination in the CTS 3.4.6.1 ACTION is provided in ITS 3.4.11 Required Actions A.2 and C.2. The ITS 3.4.11 Required Action A.2 Completion Time of 72 hours is considered reasonable for operation in MODES 1, 2, and 3 because the P/T limits are based on very conservative flaw assumptions and large factors of safety. In conditions other than MODES 1, 2, and 3, the ITS 3.4.11 Required Action C.2 Completion Time of prior to entering MODE 2 or 3 would prevent entry in the operating MODES which is consistent with the current LCO 3.0.4. This change is an additional restriction on plant operation.

M.2 The CTS 3.4.1.4 ACTION required to be taken when a recirculation pump is started without having met the temperature requirements has been changed. Currently, the CTS 3.4.1.4 ACTION only states to suspend the startup of a recirculation loop. This however, does not provide an action if the loop is already operating. ITS 3.4.11 ACTIONS A, B, and C are added which, in this condition, would require an engineering evaluation to be performed to ensure continued operation is acceptable. This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The specific requirements in CTS 4.4.6.1.1 and CTS 4.4.6.1.2 that operation be to the right of the limits lines of Figures 3.4.6.1-1, 3.4.6.1-2, 3.4.6.1-3, 3.4.6.1-4, and 3.4.6.1-5 are proposed to be relocated to the Bases. In addition, the allowance in CTS 4.4.6.1.2 and Figures 3.4.6.1-4 and 3.4.6.1-5 that with reactor water level in the normal power operation range, operation may be in the cross-hatched region of Figures 3.4.6.1-4 and 3.4.6.1-5, and the statement in Figures 3.4.6.1-1, 3.4.6.1-2, 3.4.6.1-3, 3.4.6.1-4, and 3.4.6.1-5 that the Figures are effective up to 12.8 EFPY are also proposed to be relocated to the Bases. These details are not necessary to ensure the P/T limits are met. The requirements to maintain the P/T limits in accordance with the Figures are still maintained in ITS 3.4.11, SR 3.4.11.1, and SR 3.4.11.2. Therefore, the relocated requirements are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Bases will be

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) controlled by the provisions of the proposed Bases Control Program described in Chapter 5 of the ITS.

LA.2 CTS Table 4.4.6.1.3-1 provides requirements for reactor material irradiation surveillance specimen location, lead factor, and withdrawal time. These requirements describe the reactor material irradiation surveillance specimen program requirements established by 10 CFR 50 Appendix H, and are to be relocated to the USAR. Compliance with 10 CFR 50 Appendix H is required by the NMP2 Operating License. As a result, the relocated requirements are not necessary to ensure the reactor material irradiation surveillance specimen program at NMP2 is maintained and do not need to be in the ITS to provide adequate protection of the public health and safety. Changes to the USAR will be controlled by the provisions of 10 CFR 50.59.

LA.3 The details relating to the basis for the THERMAL POWER and recirculation flow limitations in CTS 4.4.1.1.2 footnote *** (i.e., final values were determined during Startup Testing based upon actual THERMAL POWER and recirculation loop flow which will sweep the cold water from the vessel bottom head preventing stratification) are proposed to be relocated to the Bases. These details are not necessary to ensure the Surveillance Requirement is performed within the required limitations since the actual limits are still being maintained in the proposed Surveillance Requirements (SR 3.4.11.5 and SR 3.4.11.6). As such, 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.4 The details of CTS 3.4.1.4.b (and its associated Action) and CTS 4.4.1.4 relating to operational limits (maximum jet pump loop flow) during a return to two recirculation pump operation from single recirculation loop operation are proposed to be relocated to the USAR. The single loop flow rate is considered an operational limit since it is not directly related to the ability of the system to perform its safety analysis functions. The flow rate is limited only to restrict reactor vessel internals vibration to within acceptable limits during restart of the second pump. These requirements are oriented toward maintaining long term OPERABILITY of the recirculation loops and do not necessarily have an immediate impact on their OPERABILITY. As such, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the USAR will be controlled by the provisions of the 10 CFR 50.59.

"Specific"

None

Section 3.5

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4

The performance requirements of the 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 ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of 10 CFR 50.46 (Ref. 10).

The pump flow rates are verified against a system head that is equivalent to the RPV pressure expected during a LOCA. The total developed head 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 LOCAs. These values may be established during pre-operational testing. A 92 day Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements. B

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, and LPCI will cause the systems or subsystems to operate as designed, i.e., actuation of the system throughout its emergency operating sequence, which includes automatic pump startup and actuation of all automatic valves (including the LPCI flow diversion valves closed on a Reactor Vessel Water Level—Low, Level 3 or a Drywell Pressure—High (Boundary Isolation) signal) to their required positions. This Surveillance also ensures that the HPCS System will automatically restart (i.e., injection valve re-open) on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) signal and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2 (continued)

applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool or CST water level condition.

SR 3.5.2.3, SR 3.5.2.5, SR 3.5.2.6, and SR 3.5.2.7

The Bases provided for SR 3.5.1.1, SR 3.5.1.4, SR 3.5.1.5, and SR 3.5.1.8 are applicable to SR 3.5.2.3, SR 3.5.2.5, SR 3.5.2.6, and SR 3.5.2.7, respectively.

SR 3.5.2.4

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 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 when the required RHR pump is not operating or when the system is being realigned from or to the RHR shutdown cooling mode.

(continued)

ADMINISTRATIVE (continued)

A.5 CTS 4.5.1.b.1, 2, and 3 require the ECCS pumps to develop a specified flow rate against a test line pressure greater than or equal to a specified gauge pressure (i.e, psig). Proposed SR 3.5.1.4 requires the ECCS pumps to develop the specified flow rate with a specified developed head, in psid. Total developed head is a better indicator of pump performance than specifying a test line pressure, which is essentially pump discharge pressure. In addition, the pump discharge pressure is affected by suppression pool water level and suppression chamber pressure, since both of these parameters affect the suction pressure. Theoretically, a marginal pump can pass the Surveillance Requirement when the acceptance criteria is expressed as a pump discharge pressure due to either a higher suppression pool water level or a higher suppression chamber pressure, even though the pump may not be able to develop the required head to inject the required flow into the reactor vessel at the assumed reactor vessel pressure. A Surveillance Requirement with the acceptance criteria expressed in terms of "total developed head" will not be affected by a changing suppression pool water level or suppression chamber pressure, and is consistent with the NMP2 ASME Section XI Inservice Test Program acceptance criteria. Since the developed head pressures in the proposed SR are equivalent to the test line gauge pressure in the CTS, this change is only a presentation preference and is considered administrative. B

A.6 CTS 4.5.1.e.2.b) footnote * allows the ADS valve actuation test to be deferred until 12 hours after adequate reactor steam pressure is available. Adequate pressure to perform the test also implies adequate flow must be available to perform the test. As such, the footnote has been modified (proposed Note to SR 3.5.1.7) to allow deferral until adequate flow is also available. Therefore, this change is considered administrative.

A.7 CTS 4.3.3.3 states to demonstrate the response time for "each" required ECCS System. The response time for the ADS System is not assumed in any accident analysis, and their response time is listed as "N/A" (not applicable) in the appropriate plant controlled document (USAR Table 7.3-18). Therefore, this response time test has been deleted (by not referencing the ADS System in the proposed response time SR), and its deletion is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A new requirement to verify the ADS nitrogen receiver discharge header pressure is ≥ 160 psig and to verify the ADS nitrogen receiver tanks is ≥ 334 psig has been added as SR 3.5.1.3. This SR is added to ensure adequate pneumatic pressure is available for ADS operation (i.e., maintain the ADS valve open) for 13.8 hours following a LOCA and a 5 day supply of nitrogen is available to recharge the ADS accumulators. This is an additional restriction on plant operation.

M.2 CTS 4.5.1.e.2.b) requires each ADS valve to be manually opened every 18 months. The ADS valve has two solenoids, each of which can open the ADS valve. Thus, the same solenoid valve can be used to perform this SR every 18 months. Proposed SR 3.5.1.7 will now require both solenoids to be verified in the course of 48 months, as represented by the Staggered Test Basis requirement of the 24 month Frequency. This will ensure each ADS valve solenoid can open the ADS valve. This is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details of CTS 3.5.1 relating to system OPERABILITY (in this case that the ECCS subsystems shall have flow paths capable of taking suction from the suppression chamber and transferring water to the reactor vessel) are proposed to be relocated to the Bases. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. As such, 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 details of CTS 4.5.1.a.1, 4.5.1.c (including footnote †), 4.5.1.d, and 4.5.1.e.2.b) relating to methods for performing Surveillances (i.e., venting at the high point vent, verifying actuation of the system throughout its emergency operating sequence, including each automatic valve actuating to the correct position, verifying the HPCS pump restarts on level 2, verifying the HPCS suction is automatically transferred from the CST to the suppression pool on the proper signals, and verifying proper operation of the ADS valves) are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the ECCS subsystems. The requirements of ITS 3.5.1, ECCS — Operating, and the associated Surveillance Requirements are adequate to ensure the ECCS subsystems are maintained OPERABLE. NMP2 currently

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.2 (cont'd) complies with CTS 4.5.1.c footnote † by verifying that the HPCS pump will auto-restart on Reactor Vessel Water Level — Low Low, Level 2 after being manually stopped with a Level 2 signal sealed in. Compliance with the wording of the footnote can also be satisfied by verifying the HPCS pump auto-restarts on a Level 2 signal from the standby condition, since in order for the HPCS pump to be in the standby condition, it must have been manually stopped at the conclusion of the previous SR (or the previous operation of the pump). Therefore, CTS 4.5.1.c footnote † is inherently verified every time the SR is performed since the HPCS pump is in standby at the start of the SR. As such, it is not necessary to specifically identify this requirement in the Bases. As such, 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.3 The description in CTS 4.5.1.a.2 footnote * of what "correct position" means for an automatic valve is proposed to be relocated to the Bases. This detail is not necessary to ensure the automatic valves are in their proper position. The requirement of proposed SR 3.5.1.2 are adequate to ensure the automatic valves are in their proper position and the ECCS subsystems are maintained OPERABLE. As such, this 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.

LA.4 CTS 4.5.1.e.2.d) and e) are proposed to be relocated to the USAR. The leak limits and associated testing will continue to be required in order for the ADS to perform its required safety function to be considered OPERABLE. Proposed SR 3.5.1.3 is added (refer to component M.1) to address the important characteristic of whether there is sufficient pneumatic pressure available to permit the actuation of the ADS valves should an accident occur. The surveillance being relocated will continue to be performed and will identify degradation of the ADS nitrogen system pressure retention capabilities. In addition, with the leakage at the allowed leak rate limits, each ADS accumulator will provide sufficient nitrogen pressure to maintain the respective ADS valve open for at least 13.8 hours and each ADS nitrogen receiver tank will provide sufficient nitrogen pressure to maintain the respective ADS valves open for 5 days. This is sufficient time to manually recharge the accumulator. Therefore, these requirements are not needed in the ITS to ensure the ADS is maintained OPERABLE. The definition of OPERABILITY suffices. As such, these relocated requirements are not required in the ITS to provide adequate protection of the public health and safety. Changes to the USAR will be controlled by the provisions of 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LD.1 The Frequencies for performing CTS 4.5.1.c, 4.5.1.d, 4.5.1.e.2.a), 4.5.1.e.2.b), and 4.3.3.3 (proposed SRs 3.5.1.5, 3.5.1.6, 3.5.1.7, and 3.5.1.8) have been extended from 18 months to 24 months. The ECCS system functional tests, CTS 4.5.1.c (proposed SR 3.5.1.5) ensure that a system initiation signal (actual or simulated) to the automatic initiation logic of HPCS, LPCS, and LPCI will cause the subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. The ECCS response test, CTS 4.3.3.3 (proposed SR 3.5.1.8), ensures that each ECCS injection/spray subsystem responds in a manner consistent with the values assumed in the accident analysis. The ADS System functional test, CTS 4.5.1.e.2.a) (proposed SR 3.5.1.6), ensures the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by an actual or simulated initiation signal. The ADS valve actuator test, CTS 4.5.1.e.2.b) (proposed SR 3.5.1.7), ensures the valve actuator and solenoids operate properly. The proposed change will allow these Surveillances to extend their 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 current Specification 4.0.2 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 current Specification 4.0.2 and proposed SR 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. 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 small. The ECCS network has built-in redundancy so that no single failure will prevent the starting of the ECCS system. Each of the ECCS injection/spray systems are tested every three months according to the ASME Section XI inservice testing program (proposed SR 3.5.1.4) to ensure that each subsystem can provide the proper flow against a specified test pressure. This test will detect significant failures in the ECCS subsystems to perform their safety function. In addition, SRs 3.5.1.1, 3.5.1.2, and 3.5.1.3 are also performed every 31 days to ensure the ECCS subsystems are available to perform their required functions. Extending the surveillance requirement on the ADS functional test will not have a significant impact on reliability because ADS is equipped with two redundant trip systems. Additionally, the S/RVs associated with the ADS are equipped with remote manual switches so that the entire system can be operated manually as well as automatically. The primary function of ADS is to serve as a backup to the HPCS System. If HPCS were to fail, ADS must activate to lower reactor

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) pressure so that the low pressure ECCS spray/injection systems may operate. Based on the inherent system and component reliability and the testing performed during the operating cycle, the impact, if any, from this change on system availability is small. The review of historical surveillance data also demonstrated that there are no failures that would invalidate this conclusion. 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"

L.1 The number of ADS valves required to be OPERABLE in CTS 3.5.1.a and 3.5.1.b is proposed to be reduced from seven to six. CTS 3.5.1 Actions e.1 and e.2, which allow up to two of the seven ADS valves to be inoperable for a period of time prior to requiring a shutdown, and CTS 4.5.1.e.2.b), which requires each ADS valve to be opened, have also been revised to reflect this change. This change is based on the analysis summarized in Chapter 15C and in the reload analysis of Appendix A of the USAR. This analysis demonstrates adequate core cooling is provided during a small break LOCA and a simultaneous HPCS diesel generator failure (limiting LOCA) with two of the seven ADS valves out-of-service. This change reflects the credit provided through the use of NRC approved methods for calculating more realistic (yet conservative) peak cladding temperatures during accident situations. In addition, the two ADS valves out of service was approved by the NRC as documented in the initial "Safety Evaluation Report Related to the Operation of NMP2," Docket No. 50-410, Supplement No. 4 (NUREG-1047-SSER).

L.2 The pressure at which ADS is required to be OPERABLE, as specified in the CTS 3.5.1 APPLICABILITY and ACTIONS e.1 and e.2, is increased from 100 psig IN its 3.5.1 to 150 psig to provide consistency of the OPERABILITY requirements for all ECCS and RCIC equipment. Small break loss of coolant accidents at low pressures (i.e., between 100 psig and 150 psig) are bounded by analyses performed at higher pressures. The ADS is required to operate to lower the pressure sufficiently so that the low pressure coolant injection (LPCI) and low pressure core spray (LPCS) systems can provide makeup to mitigate such accidents. Since these systems can begin to inject water into the reactor pressure vessel at pressures well above 150 psig (225 psid, steam dome pressure to drywell pressure, and steam dome pressure < 225 psig for LPCI; 289 psid, steam dome pressure to drywell pressure, and steam dome pressure < 305 psig for LPCS), there is no safety significance in the ADS not being OPERABLE between 100 psig and 150 psig.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.3 The CTS 3.5.1 Action f requirement to submit a Special Report for ECCS actuation and injection is adequately addressed by 10 CFR 50.73(a)(2)(iv). This CFR section requires an LER to be submitted for any event or condition that resulted in manual or automatic ECCS "actuation." Therefore, this LER will cover any "actuation and injection" as stipulated by the Special Report. This LER is required to be submitted within 30 days which also meets the Special Report requirement of 90 days. The necessary actuation cycle information for NMP2 will be controlled by plant procedures. Regulations provide sufficient control of these provisions for their removal from Technical Specifications.

L.4 Two new ACTIONS are being added to ITS 3.5.1: (1) for the condition of one ADS valve inoperable coincident with one low pressure ECCS injection/spray system (proposed ACTION F), and (2) for the condition of HPCS inoperable coincident with one low pressure coolant injection subsystem (covered by proposed ACTION C). The current Technical Specifications require entry into LCO 3.0.3 for these conditions, implying that the plant is outside design basis. The analyses summarized in USAR Section 6.3.3 and Appendix 15C demonstrate that adequate core cooling is provided by the OPERABLE HPCS or ADS System and the remaining OPERABLE low pressure injection/spray systems. However in both conditions the redundancy has been reduced such that another single failure may not maintain the ability to provide adequate core cooling. Proposed ACTIONS C and F require a restrictive Completion Time of 72 hours since both a high pressure (ADS or HPCS) and a low pressure subsystem are inoperable. This Completion Time is based on a reliability study (Memorandum from R. L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975) and has been found to be acceptable through operating experience.

L.5 The ADS accumulator backup compressed gas system pressure alarm instrumentation Channel Functional Test and Channel Calibration requirements in CTS 4.5.1.e.1 and 4.5.1.e.2.c) do not necessarily relate directly to ADS OPERABILITY. The BWR Standard Technical Specifications, NUREG-1434, Rev. 1, does not specify alarm-only equipment to be OPERABLE to support OPERABILITY of a system or component. Control of the availability of, and necessary compensatory activities if not available, for alarms are addressed by plant operational procedures and policies. This instrumentation provides an alarm when the ADS nitrogen receiver discharge header pressure is low. Failure of the alarm does not result in the ADS being incapable of performing its intended function. The requirement to maintain the ADS nitrogen receiver discharge header pressures ≥ 160 psig and the ADS nitrogen receiver tanks ≥ 334 psig (proposed SR 3.5.1.3) will ensure sufficient nitrogen pressure is

TECHNICAL CHANGES - LESS RESTRICTIVE

L.5 (cont'd) available to operate the ADS valves. In addition, 10 CFR 50, Appendix B, Part XII requires that measuring devices used in activities affecting quality are properly controlled, calibrated, and adjusted to maintain accuracy within necessary limits. The NMP2 Operating License requires compliance with 10 CFR 50, thus if this instrumentation is used to comply with SR 3.5.1.3, it would be required to meet the 10 CFR 50, Appendix B, Part XII requirements. Therefore, this instrumentation, along with the supporting Surveillances, are proposed to be deleted.

L.6 The phrase "actual or," in reference to the automatic initiation signal, has been added to CTS 4.5.1.c (proposed SR 3.5.1.5) and 4.5.1.e.2.a (proposed SR 3.5.1.6), the Surveillance Requirements that verify each ECCS subsystem and ADS actuates on a "simulated" automatic initiation signal. This allows satisfactory "actual" automatic system initiations to be used to fulfill the Surveillance Requirements. OPERABILITY is adequately demonstrated in either case since the ECCS subsystem and ADS themselves cannot discriminate between "actual" or "simulated" signals.

L.7 CTS 4.5.1.e.2.b) requires each ADS valve to be manually opened at power. Specifically, an ADS valve disk is physically lifted by energization of a actuator solenoid, which admits nitrogen gas to a pneumatic actuator cylinder. During this test, reactor vessel steam is passed through the valve body to the suppression pool. Proposed SR 3.5.1.7 and its Bases will permit testing of the ADS valves using an alternate approach, described below, whereby the disk is not lifted off its seat at power. Each ADS actuator can be tested using either method (the current method or this alternate method).

CTS 4.4.2 and CTS 4.0.5 (proposed SR 3.4.4.1 and Specification 5.5.6, respectively) require a sample population of the S/RVs to be removed and bench tested for safety-mode lift setpoint during each refueling outage to satisfy ASME Code, Section XI testing requirements. During this bench testing, the S/RVs are also stroked using the relief-mode actuator. The safety-mode and the relief-mode bench testing of the sample population demonstrates that each installed S/RV will function properly in the safety-mode and in the relief-mode, and that the actuator of the currently installed S/RVs would successfully function. After each ADS valve is reinstalled following a bench test and after all control systems are reconnected, proposed SR 3.5.1.7 requires each ADS valve actuator to be uncoupled from its valve stem, manually actuated, and then re-coupled to the valve stem. This proposed alternate approach verifies that the ADS controls have been properly installed prior to plant startup, without physically lifting the disk off its seat. In addition, the remaining ADS valves that have not been removed for Section XI testing during a refueling outage will be tested in a similar manner.

TECHNICAL CHANGES - LESS RESTRICTIVE

L.7 (cont'd) Each Main Steam System S/RV at NMP2 is a Dikkers 8 X 10, direct-acting, spring-loaded, safety valve with attached pneumatic actuator for relief-mode operation. The valve is direct acting; the single, safety valve stem that penetrates the valve bonnet and attaches to the relief components attaches directly to the valve disk. The S/RV bonnet is directly mounted to the top of the S/RV body, with mounting facilities for the functional parts of the relief components.

NMP2 has a total of 18 S/RVs installed on the four main steam lines. All S/RVs are of the same design with 18 S/RVs performing an overpressure protection function and seven S/RVs performing a depressurization function (i.e. ADS function). These two functions are described in greater detail below:

- The overpressure protection function serves to protect the nuclear system from a pressurization transient that could lead to the failure of the reactor coolant pressure boundary.

- The ADS function serves to protect the integrity of the fuel cladding for small and intermediate breaks in the nuclear system by enabling the operation of the LPCI and LPCS Systems following maloperation of the HPCS System.

The overpressure protection function is provided by the 18 S/RVs in the safety mode or relief mode of operation. The overpressure protection analysis takes credit only for the safety mode of operation of the S/RVs. The ADS function of the seven S/RVs is provided in the relief mode of operation. These two modes of operation are discussed in greater detail below:

- The safety mode of operation consists of direct action of the reactor vessel steam pressure against a single, spring-loaded disk. This disk will lift off its seat when the reactor vessel pressure exceeds the sum of spring and frictional forces, thereby allowing vessel steam to flow directly through the seat-to-disk opening to the discharge piping and suppression pool. The safety function set pressure of each S/RV is determined by changing the compressed spring force.

- The relief mode of operation is accomplished when an automatic or manual control circuit signal provides electric power to the actuator solenoids. The actuator solenoids reposition, admitting nitrogen to the pneumatic actuator cylinder. The pneumatic actuator piston strokes vertically, raising an attached lever, which contacts a set of roller bearings coupled to the S/RV stem. The S/RV stem, which is directly attached to the disk, strokes vertically and lifts the disk off of the seat.

TECHNICAL CHANGES - LESS RESTRICTIVE

L.7 (cont'd) The relief-mode of operation can actuate each S/RV regardless of reactor vessel pressure. The pneumatic operator and linkage are designed so that a malfunction of this linkage will not inhibit the safety-mode of operation.

Each S/RV has three actuator solenoids to enable the relief-mode of operation. One actuator solenoid on each of the 18 S/RVs is energized to provide the overpressure protection function in the relief mode. Either of the two other actuator solenoids are energized on seven S/RVs to provide the ADS relief function. Therefore, the seven S/RVs that are ADS dedicated have each of their three solenoids connected to plant power supplies since these seven S/RVs provide a dual function (i.e., overpressure protection and ADS). The remaining 11 non-ADS S/RVs each have only one of their three solenoids connected to plant power supplies since these 11 S/RVs provide only an overpressure protection function in the relief mode.

When a sample population of the S/RVs are removed and bench tested each refueling outage to satisfy ASME Code Section XI testing requirements, the sample may or may not include an S/RV, which also functions as an ADS valve. This practice is acceptable for the following reasons:

- All S/RVs are identical in design. An S/RV which performs an ADS function loses its ADS functional designation when it is removed from the plant for bench testing.

- When an S/RV is removed from the plant and bench tested it is operated in the relief mode. Specifically, the actuator and the valve disk are operated by energization of each of three solenoids, one at a time.

Therefore, the complete testing of all three solenoids on a bench tested S/RV, including operation of the actuator with the lifting of the valve disk, and the identical design of the 18 S/RVs eliminates the need to require the removal of an ADS valve as part of the sample population for bench testing during a refueling outage. Accordingly, bench testing of an S/RV also tests the S/RVs capability to function as an ADS valve.

In past refueling outages at NMP2, a portion of the 18 S/RVs installed on the main steam lines were removed and bench tested for safety set pressure per Section XI of the ASME Boiler and Pressure Vessel Code. Also included was relief-mode testing which verified the capability of each of the three solenoids to enable the relief-mode function. Each of the removed S/RVs was replaced with recertified S/RVs that had been verified to have seat-to-disk leakage below

TECHNICAL CHANGES - LESS RESTRICTIVE

L.7 (cont'd) a pre-established limit. After this replacement, each ADS valve was stroked at power to satisfy CTS 4.5.1.e.2.b). This Surveillance requires physically lifting the disk off the valve seat and passing reactor vessel steam through the valve body. Following this Surveillance, NMPC occasionally experienced weeping valves from what was originally a virtually leak-free population of valves. This weeping was verified by trending S/RV tailpipe temperatures.

Each weeping S/RV directs reactor vessel steam flow through the S/RV tailpipe, which passes through the suppression pool chamber airspace and into the suppression pool water via a submerged T-quencher. During this weeping process the heated tailpipe transfers heat to the suppression chamber airspace. In addition, the weeping process transfers heat to the suppression pool water by condensation of the steam and mixing with the suppression pool contents. As a consequence, one of the Residual Heat Removal (RHR) subsystems must be periodically re-aligned from its LPCI mode of operation to provide cooling of the suppression pool water and airspace. This operation of the RHR System generates additional wear and cycling of system components, and the realignment places the system in a configuration that differs from its intended normal accident response mode of operation which is the LPCI mode of operation. Accordingly, the loop of RHR that is realigned is declared inoperable when it is cooling the suppression pool water and airspace. The transfer of heat to the suppression pool water and airspace is also a source of thermal heat loss from the power generation steam cycle. The loss of thermal heat results in a reduction of the electrical generating capacity of the unit.

The reactor vessel steam that leaks through each S/RV provides an additional source of radioactive nuclides, which becomes a potential source for personnel contamination. This contamination is undesirable during plant outages requiring entry into the primary containment.

Operation of an ADS valve with reactor steam challenges an S/RV to close after being opened for Surveillance testing. Accordingly, the current testing in of itself creates the potential for a stuck-open S/RV during reactor operation.

The proposed change permits alternate testing which eliminates the adverse potential consequences associated with operation of the ADS valves at essentially rated plant conditions. Specifically, this change eliminates a challenge to S/RVs to close after being opened for Surveillance testing. Accordingly, this proposed change reduces the likelihood of a stuck-open S/RV during reactor operation and thereby reduces the probability of a LOCA. This change has the added benefit of reducing occupational radiation exposure in the primary containment by eliminating the discharge of steam to the suppression pool from weeping S/RVs. Also this change will reduce wear on ECCS

TECHNICAL CHANGES - LESS RESTRICTIVE

L.7 (cont'd) equipment which must be operated at periodic intervals to maintain acceptable temperatures for the suppression pool water and airspace in response to weeping S/RVs. Finally, this change reduces the number of times the RHR System must be realigned from the LPCI mode of operation to the suppression pool cooling mode of operation and thereby improves the operational readiness of the RHR System to perform its automatic function in response to a LOCA.

Proposed SR 3.5.1.7 is revised to permit testing of the ADS valves using an alternate approach whereby the disk is not lifted off its seat at power. Specifically, this alternate approach entails moving the stem-mounted roller bearing assembly that couples the valve stem to the relief mode actuator upward and away from the actuator arm to allow an uncoupled actuation of the relief mode actuator (i.e., the disk would then not be coupled to the relief mode actuator and not move when the actuator is operated). As previously discussed this relief mode actuator is the same actuator that functions to enable the S/RV to perform its ADS function. The actuator would be remotely operated from the control room by energization of one of the two ADS dedicated solenoids, and visual verification would be performed for proper actuator response and range of motion. After proper actuator operation has been verified, the stem-mounted roller bearing assembly would be returned to its operating stem location.

The manual movement of the stem-mounted roller bearing assembly would be performed under a plant controlled procedure. This procedure requires independent checking to ensure that the stem mounted bearing assembly has been returned to its proper operating stem location. Accordingly, the stem mounted roller bearing assembly will be properly repositioned after uncoupled actuation of the relief mode actuator.

During removal and reinstallation process of an ADS valve, foreign materials exclusion controls are procedurally enforced. These controls require the placement of a flange protector which prevents the introduction of foreign material into the discharge piping of an ADS valve during the removal and reinstallation process. The installation and removal of the flange protector will be independently checked. Accordingly, foreign materials will be prevented from entering the S/RV discharge piping during the time frame that an ADS valve is being removed and replaced.

Based on the above evaluation, NMPC concludes that the proposed revised testing of the ADS valves, which demonstrates their depressurization function without the need for actually stroking the valve disks off the valve seats while the plant is at power, is acceptable. This proposed change to the ITS is similar

TECHNICAL CHANGES - LESS RESTRICTIVE

L.7 (cont'd) to License Amendment Number 130, dated November 18, 1996, which was requested by Grand Gulf in its letter dated May 9, 1996.

L.8 A Note has been added to CTS 4.3.3.3 (proposed SR 3.5.1.8) that exempts the ECCS instrumentation associated with each ECCS injection/spray subsystem from response time testing and allows the design instrumentation response time to be used in the determination of the ECCS RESPONSE TIME. Deletion of the response time test for this instrumentation was evaluated in NEDO-32291 "System Analysis for Elimination of Selected Response Time Testing Requirements," January 1994, and was determined to be acceptable provided the individual licensee referencing this NEDO in a plant specific license amendment request met several conditions stipulated in the generic SER approving NEDO-32291. The evaluation provided below is consistent with the guidance provided in the Staff's generic SER for NEDO-32291.

NMPC has performed a review of NEDO-32291 and determined that the NEDO generic analysis is applicable to NMP2. The equipment affected by the proposed change in the Technical Specifications is the ECCS instrumentation associated with each ECCS injection/spray subsystem. Prior to installation of a new transmitter/switch or following refurbishment of a transmitter/switch a hydraulic response time test will be performed to determine an initial sensor specific response time value. Applicable NMP2 procedures have been revised/written, as appropriate, to fulfill this recommendation. NMP2 currently does not utilize any transmitters or switches that use capillary tubes in any application that requires response time testing. Therefore, the recommendation that capillary tube testing be performed after initial installation and after any maintenance or modification activity that could damage the lines for transmitters and switches that use capillary tubes is not applicable to NMP2. Applicable calibration procedures have been revised, as appropriate, to include steps to input a fast ramp or a step change to system components during calibrations. Applicable calibration procedures have been revised, as appropriate, to assure that technicians monitor for response time degradation. In addition, technicians have received appropriate training to make them aware of the consequences of instrument response time degradation. Surveillance test procedures have been revised, as appropriate, to ensure calibrations and functional tests are being performed in a manner that allows simultaneous monitoring of both the input and output response of units under test. NMP2's compliance with the guidelines of Supplement 1 to NRC Bulletin 90-01, "Loss of Fill-Oil in Transmitters Manufactured by Rosemount," was reviewed and documented in a safety evaluation transmitted to NMPC by NRC letter dated January 18, 1995. The NRC's evaluation concluded that NMP2's responses to Bulletin 90-01 and Supplement 1 conform to the requested actions of the Bulletin. The elimination of response time testing does not affect NMPC's

TECHNICAL CHANGES - LESS RESTRICTIVE

L.8 (cont'd)

response to the Bulletin. The ECCS components for which response time testing is proposed to be eliminated has been evaluated and found to be acceptable in NEDO-32291. NMPC has reviewed the vendor recommendations for these components and confirmed that they do not contain periodic response time testing requirements.

The application of the proposed Note will allow NMPC to use design response time data for the instrumentation associated with each ECCS injection/spray subsystem in the determination of ECCS response time, and eliminate the requirement for a separate measurement of the instrumentation response time. Other Technical Specification testing requirements such as CHANNEL CALIBRATION, CHANNEL FUNCTIONAL TEST, CHANNEL CHECK, AND LOGIC SYSTEM FUNCTIONAL TEST in conjunction with actions taken in response to NRC Bulletin 90-01 are sufficient to identify failure modes or degradations in instrument response times and assure operation of the analyzed instrument loops within acceptable limits. The elimination of the response time testing of the ECCS instrumentation associated with each ECCS injection/spray subsystem will reduce the potential for inadvertent actuation of the ECCS. Accordingly, this change will reduce the likelihood of a plant transient due to an inadvertent actuation of the ECCS.

The ECCS response times requirements range from 20 to 27 seconds and, therefore, actual instrument response time which is of a much shorter duration is not important to meeting these times. ECCS instrumentation components that may experience response time degradation will continue to respond in the microsecond - to - millisecond range prior to complete failure. Accordingly, the response time degradation would have no significant adverse effect on system actuation and the instrumentation would continue to meet overall system requirements.

For each ECCS injection/spray subsystem, only the instrumentation is eliminated from the response time testing. The overall ECCS system response time requirement for each ECCS injection/spray subsystem, which includes diesel generator, injection valves, pumps and other components, still applies. The diesel generator and injection valve TS response time requirements are not eliminated.

Accordingly, based on the above evaluation, which is consistent with the guidelines of the Staff's generic SER approving NEDO-32291, the proposed elimination of ECCS instrumentation response time testing associated with each ECCS injection/spray subsystem is acceptable. The above change is similar to that approved by the NRC in License Amendment No. 184 for Brunswick Units 1 & 2.

BASES

one ADS nitrogen receiver tank pressure is ≥ 334 psig

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.3

Verification every 31 days that ADS ~~air~~ nitrogen receiver pressure is ≥ ~~150~~ 160 psig assures adequate ~~air~~ nitrogen discharge header pressure for reliable ADS operation. The accumulator on each ADS valve provides ~~pneumatic~~ pressure for valve actuation. The designed ~~pneumatic~~ nitrogen supply pressure requirements for the accumulator are such that, following a failure of the ~~pneumatic~~ nitrogen supply to the accumulator, at least ~~two~~ one valve actuations can occur with the drywell at ~~70%~~ 100% of design pressure (Ref. ~~14~~ 15). The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ~~150~~ 160 psig is provided by the ADS ~~Instrument Air Supply System~~ nitrogen receiver discharge header. The 31 day Frequency takes into consideration administrative control over operation of the ~~Instrument Air Supply System~~ nitrogen receiver tanks and alarms for low ~~air~~ nitrogen pressure.

Nitrogen receiver tanks. The minimum ADS nitrogen receiver tank pressure of 334 psig ensures a 5 day supply of nitrogen is available to recharge the ADS accumulators.

SR 3.5.1.4

The performance requirements of the 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 ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of 10 CFR 50.46 (Ref. 10).

The pump flow rates are verified against a system head that is equivalent to the RPV pressure expected during a LOCA. The total ~~system pump outlet pressure~~ developed head 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 LOCAs. These values may be established during pre-operational testing. A 92 day Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance ~~test~~

(continued)

BASES

ACTIONS

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

move to previous page

The 4 hour Completion Time to restore at least one 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.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2

195 ft.

The minimum water level of [12.67 ft] required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the ECCS 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 CST.

When the suppression pool level is <[12.67 ft], the HPCS System is considered OPERABLE only if it can take suction from the CST and the CST water level is sufficient to provide the required NPSH for the HPCS pump. Therefore, a verification that either the suppression pool water level is ≥[12.67 ft], or the HPCS System is aligned to take suction from the CST and the CST contains ≥[170,000] gallons of water, equivalent to [18] ft, ensures that the HPCS System can supply makeup water to the RPV. Insert SR

195 ft.

253,000

26.9

135,000 gallons of

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

SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6, and SR 3.5.2.7

The Bases provided for SR 3.5.1.1, SR 3.5.1.4, and SR 3.5.1.5 and SR 3.5.1.8 are applicable to SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6, and SR 3.5.2.7, respectively.

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ---------NOTE--------- Only applicable to penetration flow paths with two or more PCIVs. ---------- One or more penetration flow paths with two or more PCIVs inoperable except due to leakage not within limit.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour
C. ---------NOTE--------- Only applicable to penetration flow paths with only one PCIV. ---------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limit.	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 (A)
		AND
		72 hours for EFCVs and penetrations with a closed system (B)
	AND	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 --------NOTES-------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or more penetration flowpaths with secondary containment bypass leakage rate, MSIV leakage rate, or hydrostatically tested line leakage rate not within limit.	D.1 Restore leakage rate to within limit.	4 hours for hydrostatically tested line leakage not on a closed system AND 4 hours for secondary containment bypass leakage AND 8 hours for MSIV leakage AND 72 hours for hydrostatically tested line leakage on a closed system
E. One or more penetration flow paths with one or more containment purge exhaust valves not within purge valve leakage limits.	E.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND	24 hours (continued)

Table 3.6.1.3-1 (page 2 of 2)
Secondary Containment Bypass Leakage Paths Leakage Rate Limits

VALVE NUMBER	PER VALVE LEAK RATE (SCFH)
2CPS*SOV119 2CPS*SOV120 2CPS*SOV121 2CPS*SOV122	0.625
2IAS*SOV164 2IAS*V448	0.9375
2IAS*SOV165 2IAS*V449	0.9375
2GSN*SOV166 2GSN*V170	(a)
2IAS*SOV166 2IAS*SOV184	(a)
2IAS*SOV167 2IAS*SOV185	(a)
2IAS*SOV168 2IAS*SOV180	(a)
2CPS*SOV132 2CPS*V50	(a)
2CPS*SOV133 2CPS*V51	(a)

(a) The combined leak rate for these penetrations shall be ≤ 3.6 SCFH. The assigned leakage rate through a penetration shall be that of the valve with the highest leakage rate in that penetration. However, if a penetration is isolated by one closed and de-activated automatic valve, closed manual valve, or blind flange, the leakage through the penetration shall be the actual pathway leakage.

3.6 CONTAINMENT SYSTEMS

3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

LCO 3.6.1.7 Each suppression chamber-to-drywell vacuum breaker shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One line with one or more suppression chamber-to-drywell vacuum breakers inoperable for opening.	A.1 Restore the vacuum breaker(s) to OPERABLE status.	72 hours
B. ---------NOTE--------- Separate Condition entry is allowed for each suppression chamber-to-drywell vacuum breaker line. ---------- One or more lines with one suppression chamber-to-drywell vacuum breaker not closed.	B.1 Close the open vacuum breaker.	72 hours

(continued)

3.6 CONTAINMENT SYSTEMS

3.6.3.1 Primary Containment Hydrogen Recombiners

LCO 3.6.3.1 Two primary containment hydrogen recombiners shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One primary containment hydrogen recombiner inoperable.	A.1	--------NOTE--------- LCO 3.0.4 is not applicable. ---------- Restore primary containment hydrogen recombiner to OPERABLE status.	30 days
B. Two primary containment hydrogen recombiners inoperable.	B.1	Verify by administrative means that the hydrogen and oxygen control function is maintained.	1 hour AND Once per 12 hours thereafter
	AND		
	B.2	Restore one primary containment hydrogen recombiner to OPERABLE status.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.3	Verify one secondary containment access door in each access opening is closed.	31 days
SR 3.6.4.1.4	Verify the secondary containment can be drawn down to ≥ 0.25 inch of vacuum water gauge in ≤ 66.7 seconds using one standby gas treatment (SGT) subsystem.	24 months on a STAGGERED TEST BASIS for each SGT subsystem
SR 3.6.4.1.5	Verify the secondary containment can be maintained ≥ 0.25 inch of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 2670 cfm.	24 months on a STAGGERED TEST BASIS for each SGT subsystem

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a design basis Loss of Coolant Accident (LOCA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. Additionally, this structure provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions. B

The isolation devices for the penetrations in the primary containment boundary are a part of the primary containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. Primary containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks"; B

c. All equipment hatches are closed and sealed; and B

d. The sealing mechanism associated with each primary containment penetration (e.g., welds, bellows, or O-rings) is OPERABLE (i.e., OPERABLE such that the primary containment leakage limits are met). B

(continued)

BASES

BACKGROUND (continued)

This Specification ensures that the performance of the primary containment, in the event of a Design Basis Accident (DBA), meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 1.1% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 39.75 psig (Ref. 4).

Primary containment satisfies Criterion 3 of Reference 5.

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required 10 CFR 50 Appendix J Testing Program Plan leakage test. At this time, the applicable leakage limits must be met. In addition, the leakage from the drywell to the suppression chamber must be limited to ensure the primary containment pressure does not exceed design limits. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those

(continued)

BASES

LCO (continued)

leakage rates assumed in the safety analysis. Individual leakage rates specified for the primary containment air locks are addressed in LCO 3.6.1.2.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, primary containment is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

A.1

In the event that primary containment is inoperable, primary containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining primary containment OPERABILITY during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring primary containment OPERABILITY) occurring during periods where primary containment is inoperable is minimal.

B.1 and B.2

If primary containment cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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 10 CFR 50 Appendix J Testing Program Plan. Failure to meet air lock leakage limit (SR 3.6.1.2.1), secondary containment bypass leakage limit

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1 (continued)

(SR 3.6.1.3.11), resilient seal primary containment purge valve leakage limit (SR 3.6.1.3.6), or main steam isolation valve leakage limit (SR 3.6.1.3.12) 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 Testing Program Plan.

As left leakage prior to the first startup after performing a required 10 CFR 50 Appendix J Testing Program Plan 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 Testing Program Plan. B B

SR 3.6.1.1.2 and SR 3.6.1.1.3

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. SR 3.6.1.1.2 measures drywell-to-suppression chamber differential pressure to ensure that the leakage paths that would bypass the suppression pool are within allowable limits. The suppression chamber-to-drywell vacuum breakers are the most likely source of potential bypass leakage, therefore, these valves are normally tested on a more frequent basis.

Satisfactory performance of SR 3.6.1.1.2 can be achieved by establishing a known differential pressure (≥ 3.0 psid) between the drywell and the suppression chamber and verifying that the $A/\sqrt{k}$ calculated from the measured bypass leakage is equivalent to that through an area ≤ 0.0054 ft^2. The leakage test is performed at the same Frequency as the Type A testing requirements of the 10 CFR 50 Appendix J Testing Program Plan. This Frequency was developed since historically the leakage is much less than the design value and that the most credible source of potential bypass

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.2 and SR 3.6.1.1.3 (continued)

leakage, the suppression chamber-to-drywell vacuum breakers will normally be tested more frequently in accordance with SR 3.6.1.1.3. Two consecutive as-found test failures of SR 3.6.1.1.2, however, would indicate unexpected primary containment degradation; in this event, as the Note indicates, increasing the Frequency to once every 24 months is required until the situation is remediated as evidenced by passing two consecutive tests.

Conservative test criteria was chosen for SR 3.6.1.1.3 based on the assumed bypass leakage in the LOCA analysis. The 24 month Frequency specified for SR 3.6.1.1.3 was developed considering it is prudent that this Surveillance be performed during a unit outage. A Note has been added to SR 3.6.1.1.3 which provides an allowance not to perform SR 3.6.1.1.3 when SR 3.6.1.1.2 is required to be performed since SR 3.6.1.1.2 will provide adequate information on the capacity of the pressure suppression function of the primary containment.

REFERENCES

1. USAR, Section 6.2.
2. USAR, Section 15.6.5.
3. 10 CFR 50, Appendix J, Option B.
4. USAR, Section 6.2.6.1.
5. 10 CFR 50.36(c)(2)(ii).

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the primary containment air lock is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door, then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the primary containment boundary is not intact (during access through the OPERABLE door). The allowance to open the OPERABLE door, even if it means the primary containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the OPERABLE door is expected to be open. The required administrative controls consist of stationing a dedicated individual to assure closure of the OPERABLE door except during the entry and exit, and to assure the OPERABLE door is relocked after completion of the containment entry and exit. 1B 1B

Note 2 has been included to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by a third Note, which ensures appropriate remedial actions are taken when necessary, if air lock leakage results in exceeding overall containment leakage rate acceptance criteria. Pursuant to LCO 3.0.6, ACTIONS are not required even if primary containment leakage

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary containment isolation within the time limits specified for those PCIVs designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA.

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that the primary containment function assumed in the safety analysis will be maintained. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges (which include plugs and caps as listed in Reference 1), and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration, except for penetrations isolated by excess flow check valves, so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analysis. One of these barriers may be a closed system.

The 12 and 14 inch primary containment purge valves are PCIVs that are qualified for use during all operational conditions.. The 12 and 14 inch primary containment purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure the primary containment boundary is maintained. However, the purge valves may be open when being used for pressure control, inerting, de-inerting, ALARA, or air quality considerations since they are fully qualified. A two inch bypass line is provided when the primary containment full flow line to the Standby Gas Treatment (SGT) System is isolated.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The PCIVs LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory, and establishing the primary containment boundary during major accidents. As part of the primary containment boundary, PCIV OPERABILITY supports leak tightness of primary containment. Therefore, the safety analysis of any event requiring isolation of primary containment is applicable to this LCO.

The DBAs that result in a release of radioactive material for which the consequences are mitigated by PCIVs are a loss of coolant accident (LOCA) and a main steam line break (MSLB) (Refs. 2 and 3). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment purge valves) are minimized. Of the events analyzed in References 2 and 3, the LOCA is the most limiting event due to radiological consequences. The closure time of the main steam isolation valves (MSIVs) is a significant variable from a radiological standpoint. The MSIVs are required to close within 3 to 5 seconds since the 3 second closure time is assumed in the MSIV closure (the most severe overpressurization transient) analysis (Ref. 4) and 5 second closure time is assumed in the MSLB analysis (Ref. 3). Likewise, it is assumed that the primary containment isolates such that release of fission products to the environment is controlled.

The DBA analysis assumes that isolation of the primary containment is complete and leakage terminated, except for the maximum allowable leakage, L_a, prior to fuel damage.

The single failure criterion required to be imposed in the conduct of unit safety analyses was considered in the original design of the primary containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred.

PCIVs satisfy Criterion 3 of Reference 5.

(continued)

BASES (continued)

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to minimizing the loss of reactor coolant inventory and establishing the primary containment boundary during a DBA.

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. The valves covered by this LCO are listed with their associated stroke times in Ref. 1. B

The normally closed manual PCIVs are considered OPERABLE when the valves are closed, or open under administrative controls. Normally closed automatic PCIVs, which are required by design (e.g., to meet 10 CFR 50 Appendix R requirements) to be de-activated and closed, are considered OPERABLE when the valve is closed and de-activated. These passive isolation valves and devices are those listed in Reference 1. Purge valves with resilient seals, secondary containment bypass valves, MSIVs, and hydrostatically tested valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing. B B

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the primary containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, most PCIVs are not required to be OPERABLE and the primary containment purge valves are not required to be normally closed in MODES 4 and 5. Certain valves are required to be OPERABLE, however, to prevent inadvertent reactor vessel draindown. These valves are those whose associated instrumentation is required to be OPERABLE according to LCO 3.3.6.1, "Primary Containment Isolation Instrumentation." (This does not include the valves that isolate the associated instrumentation.)

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow path(s) to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

A second Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable PCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable PCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by Notes 3 and 4. Note 3 ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable PCIV (e.g., an Emergency Core Cooling System subsystem is inoperable due to a failed open test return valve). Note 4 ensures appropriate remedial actions are taken when the primary containment leakage limits are exceeded. Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require the proper actions be taken.

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable, except for secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for

B

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

main steam lines). The specified time period of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside the primary containment and capable of being mispositioned are in the correct position. The Completion Time for this verification of "once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For devices inside the primary containment the specified time period of "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days," is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and the existence of other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two or more PCIVs. For penetration flow paths with one PCIV, Condition C provides appropriate Required Actions.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two or more PCIVs inoperable, except for secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within limit, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. B

Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two or more PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

C.1 and C.2

When one or more penetration flow paths with one PCIV inoperable, except for secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within limit, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use B

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within 4 hours except for excess flow check valves (EFCVs) and penetrations with a closed system and 72 hours for EFCVs and penetrations with a closed system. The Completion Time of 4 hours for valves other than EFCVs and in penetrations with a closed system is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The 72 hour Completion Time for penetrations with a closed system is reasonable considering the relative stability of the closed system piping or water seal (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The closed system must meet the requirements of Ref. 6. The Completion Time of 72 hours for EFCVs is also reasonable considering the mitigating effects of the small pipe diameter and restricting orifice, and the isolation boundary provided by the instrument. In the event the affected penetration is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those devices outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating this Condition is applicable only to those penetration flow paths with only one PCIV. For penetration flow paths with two or more PCIVs, Conditions A and B provide the appropriate Required Actions. This Note is necessary since this Condition is written specifically to address those penetrations with a single PCIV.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Required Action C.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

D.1

With the secondary containment bypass leakage rate (SR 3.6.1.3.11), MSIV leakage rate (SR 3.6.1.3.12), or hydrostatically tested line leakage rate (SR 3.6.1.3.13) not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage rate must be restored to within limit within the Completion Times appropriate for each type of valve leakage: a) hydrostatically tested line leakage not on a closed system and secondary containment bypass leakage are required to be restored within 4 hours; b) MSIV leakage is required to be restored within 8 hours; and c) hydrostatically tested line leakage on a closed system is required to be restored within 72 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 4 hour Completion Time for hydrostatically tested line leakage not on a closed system and for secondary containment bypass leakage is reasonable considering the time required to restore the leakage by isolating the penetration and the relative importance of

(continued)

BASES

ACTIONS

D.1 (continued)

secondary containment bypass leakage to the overall containment function. The Completion Time of 8 hours for MSIV leakage allows a period of time to restore the MSIV leakage and is acceptable given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown. The 72 hour Completion Time for hydrostatically tested line leakage on a closed system is acceptable based on the available water seal expected to remain as a gaseous fission product boundary during the accident and, in many cases, the associated closed system. The closed system must meet the requirements of Ref. 6.

E.1, E.2, and E.3

In the event one or more containment purge exhaust valves are not within the purge valve leakage limits, purge exhaust valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, and blind flange. If a purge exhaust valve with resilient seals is utilized to satisfy Required Action E.1 it must have been demonstrated to meet the leakage requirements of SR 3.6.1.3.6. The specified Completion Time is reasonable, considering that one containment purge valve remains closed so that a gross breach of containment does not exist.

In accordance with Required Action E.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the

(continued)

BASES

ACTIONS

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

previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Required Action E.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment once they have been verified to be in the proper position, is low.

For the containment purge exhaust valve with resilient seal that is closed in accordance with Required Action E.1, SR 3.6.1.3.6 must be performed at least once every 92 days. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge exhaust valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.6 is 184 days. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown acceptable based on operating experience.

F.1 and F.2

If any Required Action and associated Completion Time cannot be met in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1 and G.2

If any Required Action and associated Completion Time cannot be met for PCIV(s) required OPERABLE in MODE 4 or 5, the plant must be placed in a condition in which the LCO does not apply. Action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. If suspending the OPDRVs would result in closing the residual heat removal (RHR) shutdown cooling isolation valves, an alternative Required Action is provided to immediately initiate action to restore the valves to OPERABLE status. This allows RHR shutdown cooling to remain in service while actions are being taken to restore the valve.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

This SR verifies that the 12 inch and 14 inch primary containment purge valves are closed as required or, if open, opened for an allowable reason.

The SR is modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA, or air quality considerations for personnel entry, or for Surveillances that require the valves to be open, provided that either: a) the SGT System is OPERABLE (i.e., both subsystems); or b) the primary containment full flow line to the SGT System is isolated and one SGT subsystem is OPERABLE. These primary containment purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The allowance is intended to balance the operational needs of the unit with the requirement to preclude a radiological release through the purge exhaust

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1 (continued)

lines. With the primary containment atmosphere being exhausted through the containment full flow line to the SGT System, a pressure transient could damage the operating SGT subsystem. Thus both subsystems are required to be OPERABLE when the full flow line is in service. This ensures that, if an accident occurs that damages the operating SGT subsystem, the remaining SGT subsystem is still available to perform the intended SGT System safety function. When the full flow line is not in service (i.e., the two inch bypass valve is open), then only one SGT subsystem is required to be OPERABLE since a pressure transient cannot damage the operating SGT subsystem. The 31 day Frequency is consistent with other primary containment isolation valve requirements discussed in SR 3.6.1.3.2.

SR 3.6.1.3.2

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the primary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those PCIVs outside primary containment, and capable of being mispositioned, are in the correct position. Since verification of position for PCIVs outside primary containment is relatively easy, the 31 day Frequency was chosen to provide added assurance that the PCIVs are in the correct positions. This SR does not apply to valves and blind flanges that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes are added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.2 (continued)

reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in the proper position, is low. A second Note is included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time the PCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.3

This SR verifies that each primary containment manual isolation valve and blind flange located inside primary containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For PCIVs inside primary containment, the Frequency of "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days," is appropriate since these PCIVs are operated under administrative controls and the probability of their misalignment is low. This SR does not apply to valves and blind flanges that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes are added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA and personnel safety. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in their proper position, is low. A second Note is included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.3 (continued)

These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.4

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. Other administrative controls, such as those that limit the shelf life and operating life, as applicable, of the explosive charges, must be followed. The 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

SR 3.6.1.3.5

Verifying the isolation time of each power operated, automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.7. The isolation time test ensures that each valve will isolate in a time period less than or equal to that assumed in the safety analysis. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.1.3.6

For primary containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J Option B (Ref. 7), is required to ensure OPERABILITY. The primary containment purge supply valves, which are secondary containment bypass leakage pathway valves, are tested at a pressure of 40.0 psig and the primary containment purge exhaust valves, which are not secondary containment bypass leakage pathway valves, are tested at P_a, 39.75 psig. The leakage limit for the 12 inch supply and exhaust valves are 3.75 scfh while the 14 inch supply and exhaust valve leakage limit is 4.38 scfh.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.6 (continued)

Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation, and the importance of maintaining these penetrations leak tight (due to the direct path between primary containment and the environment in some cases), a Frequency of 184 days was established. Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

SR 3.6.1.3.7

Verifying that the full closure isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The full closure isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA and transient analyses. The Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.1.3.8

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.9

This SR requires a demonstration that each EFCV is OPERABLE by verifying that the valve actuates to the isolation position on an actual or simulated instrument line break condition. This SR provides assurance that the instrumentation line EFCVs will perform as designed. Some hydraulic EFCVs are tested by providing an instrument line break signal with reactor pressure above 600 psig. Testing above this pressure range provides a high degree of assurance that these valves will close during an instrument line break while at normal operating pressure. The remaining hydraulic EFCVs are tested with process fluid or demin water at low pressure. The pneumatic EFCVs are tested by providing an instrument line break signal with pressure at approximately 15 psig to 150 psig. These test pressures are selected to simulate the actual operating conditions the EFCVs are expected to experience during instrument line breaks outside containment.

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 that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.10

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired, and shall be installed in accordance with the manufacturer's recommendations. Other administrative controls, such as those that limit the shelf life and operating life, as applicable, of the explosive charges, must be followed. The Frequency of 24 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.4).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.11

This SR ensures that the leakage rate of secondary containment bypass leakage paths (with the exception of the MSIVs, which are tested per SR 3.6.1.3.12) is less than or equal to the specified leakage rate. While the MSIVs are also classified as secondary containment bypass leakage pathway valves, they are evaluated according to SR 3.6.1.3.12, and if not within limits, actions are required to be taken in accordance with ACTION D. This provides assurance that the assumptions in the radiological evaluations that form the basis of the USAR (Ref. 2) are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. The Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan.

Bypass leakage is considered part of L_a.

SR 3.6.1.3.12

The analyses in Reference 1 are based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be $\leq$ 24 scfh when tested at 40 psig. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by the 10 CFR 50 Appendix J Testing Program Plan.

MSIV leakage is considered part of L_a.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.13

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 1 are met. The combined leakage rates must be demonstrated in accordance with the leakage test Frequency required by the 10 CFR 50 Appendix J Testing Program Plan. 1 B

REFERENCES

1. Technical Requirements Manual.
2. USAR, Section 15.6.5.
3. USAR, Section 15.6.4.
4. USAR, Section 15.2.4.
5. 10 CFR 50.36(c)(2)(ii).
6. USAR, Section 6.2.4.3.2.
7. 10 CFR 50, Appendix J Option B.

B

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Drywell Air Temperature

BASES

BACKGROUND	Heat loads from the drywell, as well as piping and equipment, add energy to the airspace and raise airspace temperature. Coolers included in the unit design remove this energy and maintain an appropriate average temperature. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). This drywell air temperature limit is an initial condition input for the Reference 1 safety analyses.
APPLICABLE SAFETY ANALYSES	Primary containment performance for the DBA is evaluated for a entire spectrum of break sizes for postulated loss of coolant accidents (LOCAs) inside containment (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature. Analyses assume an initial average drywell air temperature of 150°F. Maintaining the expected initial conditions ensures that safety analyses remain valid and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of 340°F (Ref. 1). Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment, and needed to mitigate the effects of a DBA, is designed to operate and be capable of operating under environmental conditions expected for the accident. In addition, the drywell average air temperature is the limiting initial condition used to determine the maximum negative differential pressure across the primary containment boundary following an inadvertent drywell spray actuation (Ref. 1). Drywell air temperature satisfies Criterion 2 of Reference 2.
LCO	With an initial drywell average air temperature less than or equal to the LCO temperature limit, the peak accident temperature is maintained below the drywell design temperature and the design negative differential pressure

(continued)

BASES

LCO (continued)

across the primary containment boundary is not exceeded. As a result, the ability of primary containment to perform its design function is ensured. (B)

APPLICABILITY

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

ACTIONS

A.1

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

B.1 and B.2

If the drywell average air temperature cannot be restored to within the limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1

Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary containment analyses. In order to determine the drywell average air temperature, an arithmetic average is calculated, using measurements taken at locations within the drywell selected to provide a representative sample of the overall drywell atmosphere.

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The primary containment utilizes a Mark II over/under pressure suppression configuration, with the suppression pool located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The suppression pool must quench all the steam released through the downcomer lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment that ensures that the peak containment pressure is maintained below the design value (45 psig). Suppression pool average temperature (along with LCO 3.6.2.2, "Suppression Pool Water Level") is a key indication of the capacity of the suppression pool to fulfill these requirements. 1B

The technical concerns that lead to the development of suppression pool average temperature limits are as follows:

a. Complete steam condensation;

b. Primary containment peak pressure and temperature;

c. Condensation oscillation (CO) loads; and

d. Chugging loads.

APPLICABLE SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Reference 1 for LOCAs and Reference 2 for the suppression pool temperature analyses required by Reference 3). An initial pool temperature of 90°F is assumed for the Reference 1 and 2 analyses. Reactor shutdown at a pool temperature of 110°F and vessel depressurization at a pool

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. Average temperature is determined by taking an arithmetic average of at least one OPERABLE post accident monitoring instrumentation channel in each suppression pool quadrant. Alternatively, average temperature can be determined by taking an arithmetic average of 10 OPERABLE suppression pool water temperature channels, which are distributed in different suppression pool sectors. There is no divisional requirement with respect to the instrument channels for this SR. The 24 hour Frequency has been shown to be acceptable based on operating experience. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which testing will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. USAR, Section 6.2.1.1.3.
2. USAR, Appendix 6A.10.1.
3. NUREG-0783.
4. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS

A.1 (continued)

accumulation exceeding this limit, and the low probability of failure of the OPERABLE primary containment hydrogen recombiner.

Required Action A.1 has been modified by a Note stating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in amounts capable of exceeding the flammability limits, the low probability of the failure of the OPERABLE recombiner, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limits.

B.1 and B.2

With two primary containment hydrogen recombiners inoperable, the ability to perform the hydrogen and oxygen control function via an alternate capability must be verified by administrative means within 1 hour. The alternate hydrogen and oxygen control capability is provided by the Primary Containment Vent, Purge, and Nitrogen System and one RHR drywell spray subsystem. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen and oxygen control function does not exist. In addition, the alternate hydrogen and oxygen control system capability must be verified once per 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen and oxygen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen and oxygen control system. If the ability to perform the hydrogen and oxygen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen and oxygen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in the amounts capable of exceeding the flammability limits.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment Oxygen Concentration

BASES

BACKGROUND

The primary containment is designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen < 4.0 v/o works together with the Hydrogen Recombiner System (LCO 3.6.3.1, "Primary Containment Hydrogen Recombiners") and the RHR Drywell Spray System (LCO 3.6.1.6, "RHR Drywell Spray") to provide redundant and diverse methods to mitigate events that produce hydrogen and oxygen. For example, an event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain ≤ 5.0 v/o and no combustion can occur. Long term generation of both hydrogen and oxygen from radiolytic decomposition of water may eventually result in a combustible mixture in primary containment, except that the hydrogen recombiners remove hydrogen and oxygen gases faster than they can be produced from radiolysis and again no combustion can occur. This LCO ensures that oxygen concentration does not exceed 4.0 v/o during operation in the applicable conditions. B

APPLICABLE SAFETY ANALYSES

The Reference 1 calculations assume that the primary containment is inerted when a Design Basis Accident loss of coolant accident occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of metal water reaction in the reactor core will not produce combustible gas mixtures in the primary containment. Oxygen, which is subsequently generated by radiolytic decomposition of water, is recombined by the hydrogen recombiners (LCO 3.6.3.1) more rapidly than it is produced.

Primary containment oxygen concentration satisfies Criterion 2 of Reference 2.

(continued)

BASES

ACTIONS

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

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. Entering LCO 3.0.3 while in Mode 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration. 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.

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches and one access door in each access opening are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. In this application, the term "sealed" has no connotation of leak tightness. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed. An access opening contains one inner and one outer door. In some cases, a secondary containment barrier contains multiple inner or multiple outer doors. For these cases, the access openings share the inner door or the outer door, i.e., the access openings have a common inner door or outer door. The intent is not to breach the secondary containment

1 B

B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.2 and SR 3.6.4.1.3 (continued)

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 these SRs has been shown to be adequate based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator.

SR 3.6.4.1.4 and SR 3.6.4.1.5

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 and SR 3.6.4.1.5 verify that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can rapidly be established and maintained. This cannot be accomplished if the secondary containment boundary is not intact. The establishment of this pressure is confirmed by SR 3.6.4.1.4, which demonstrates that the secondary containment can be drawn down to ≥ 0.25 inches of vacuum water gauge in ≤ 66.7 seconds with the initial secondary containment pressure ≥ 0 psig, using one SGT subsystem. SR 3.6.4.1.5 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 2670 cfm. This flow rate is the assumed secondary containment leak rate during the drawdown period. 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. The drawdown test conditions must be adjusted based on the methodology in Reference 5 to compensate for actual inleakage flow and initial conditions during the test. Since these SRs are secondary containment boundary integrity tests, they need not be performed with each SGT subsystem. The SGT subsystem used for these Surveillances is staggered to ensure that in addition to the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.4 and SR 3.6.4.1.5 (continued)

requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. However, since these Surveillances are secondary containment boundary integrity tests, the inoperability of the SGT System does not constitute a failure of these Surveillances. Operating experience has shown the secondary containment boundary usually passes these Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 3.6A.2.1.5.
2. USAR, Section 15.6.5.
3. USAR, Section 15.7.4.
4. 10 CFR 50.36(c)(2)(ii).
5. USAR, Section 6.2.3.4.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Refs. 1 and 2). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, that are released during certain operations when primary containment is not required to be OPERABLE, or that take place outside primary containment, are maintained within the secondary containment boundary.

The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), and blind flanges are considered passive devices.

Automatic SCIVs (i.e., dampers) close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or other accidents.

Other penetrations are isolated by the use of valves in the closed position or blind flanges (which includes plugs and caps as listed in Reference 3). B

APPLICABLE SAFETY ANALYSES

The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accidents for which the secondary containment boundary is required are a loss of coolant accident (Ref. 1) and a fuel handling accident (Ref. 2). The secondary containment performs no active function in response to each of these limiting events, but the boundary established by SCIVs is required to ensure that leakage from the primary containment is processed by the Standby Gas Treatment (SGT) System before being released to the environment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of Reference 4. B

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The power operated, automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 3. B

The normally closed manual SCIVs are considered OPERABLE when the valves are closed, or open under administrative controls. These passive isolation valves or devices are listed in Reference 3. B

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low. B

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves. This clarifies that only Condition A is entered if one SCIV is inoperable in each of two penetrations.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are

(continued)

BASES

SURVEILLANCE

SR 3.6.4.2.1 (continued)

manipulation. Rather, it involves verification that those SCIVs in secondary containment that are capable of being mispositioned are in the correct position.

Since these SCIVs are readily accessible to personnel during normal unit operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide added assurance that the SCIVs are in the correct positions.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these SCIVs, once they have been verified to be in the proper position, is low. 1 B

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.

SR 3.6.4.2.2

Verifying the isolation time of each power operated, automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The Frequency of this SR is 92 days.

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent leakage of radioactive material from secondary containment following

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.3 (continued)

a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 15.6.5.
2. USAR, Section 15.7.4.
3. Technical Requirements Manual. B
4. 10 CFR 50.36(c)(2)(ii). B

BASES

ACTIONS

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

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. Entering LCO 3.0.3 while in Mode 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating (from the control room using the manual initiation switch) each SGT subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system. B

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 6). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specified test frequencies and additional information are discussed in detail in the VFTP.

(continued)

A.1

Specification 3.6.1.1

SURVEILLANCE REQUIREMENTS

4.6.2.1 (Continued)

d. At least once per 18 months by conducting a visual inspection of the exposed accessible interior and exterior surfaces of the suppression chamber.* L.3 B

e. At least every outage requiring the performance of a Containment Integrated Leak Rate Test, as scheduled in conformance with the criteria specified in the 10CFR50 Appendix J Testing Program Plan described in Section 6.8.4.f, by conducting a drywell-to-suppression chamber bypass leak test at an initial differential pressure of 3 psi and verifying that the A/√K calculated from the measured leakage is within the specified limit of 0.0054 square feet.

SR 3.6.1.1.2

1. 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. L.4 B

2. If two consecutive tests fail to meet the specified limit, a test shall be performed at least each refueling outage (24 months) until two consecutive tests meet the specified limit, at which time the original test schedule may be resumed. LD.1

3. The provisions of Specification 4.0.2 do not apply. A.11

f. During each refueling outage (24 months) for which the drywell-to-suppression chamber bypass leak test in Specification 4.6.2.1.e is not conducted, by conducting a test of the four drywell-to-suppression chamber bypass leak paths containing the suppression chamber vacuum breakers at a differential pressure of at least 3 psi and LD.1

SR 3.6.1.1.3

1. verifying that the total leakage area A/√K contributed by all four bypass leak paths is less than or equal to 24% of the specified limit, and

2. the leakage area for any one of the four bypass leak paths is less than or equal to 12% of the specified limit.

* Includes each vacuum relief valve and associated piping. L.3 B

ADMINISTRATIVE

A.7 A definition for L_a in CTS 3.6.1.2.a is also currently included in the 10 CFR 50 Appendix J Testing Program Plan in CTS 6.8.4.f. Since this definition will remain in ITS 5.5.12, 10 CFR 50 Appendix J Testing Program Plan, its deletion in CTS 3.6.1.2.a is considered administrative. Any technical changes to the requirements, if any, will be discussed in the Discussion of Changes for ITS: 5.5.

A.8 Primary containment structural integrity requirements specified in CTS 3.6.1.4 and 4.6.1.4.1 are proposed to be a supporting Surveillance for Primary Containment OPERABILITY (proposed SR 3.6.1.1.1); the essence of an OPERABLE containment is its leak-tightness. The existing Technical Specifications contain details which are also found in 10 CFR 50 Appendix J: accessible interior and exterior surfaces. These regulations require licensee compliance, cannot be revised by the licensee, and are addressed by direct reference in the Technical Specifications. The details of the regulations within the Technical Specifications are repetitious and unnecessary. B

Therefore, retaining the requirement to meet the requirements of 10 CFR 50 Appendix J, as modified by approved exemptions (as described in the 10 CFR 50 Appendix J Testing Program Plan in Section 5.5 of the ITS), and eliminating the Technical Specification details that are found in Appendix J, is considered a presentation preference, which is administrative.

A.9 The drywell-to-suppression chamber bypass leakage requirement of CTS 3.6.2.1.b is proposed to be a supporting Surveillance for Primary Containment OPERABILITY (proposed SR 3.6.1.1.2); bypass leakage within limit is essential for the primary containment to perform its pressure suppression function and to ensure the primary containment design pressure is not exceeded. Therefore, the actual LCO statement is not needed since it is part of Primary Containment OPERABILITY (ITS 3.6.1.1). This change is considered a presentation preference, which is administrative.

A.10 Not used. B

A.11 CTS 4.6.2.1.e requires a drywell-to-suppression chamber bypass leak test to be performed in accordance with the criteria specified in the 10 CFR 50 Appendix J Testing Program Plan. CTS 4.6.2.1.e.3, which only modifies CTS 4.6.2.1.e (CTS 4.6.2.1.e.1, 2, and 3 all modify the requirements of CTS 4.6.2.1.e - they are not stand alone requirements nor do they modify each other), states that the provisions of CTS 4.0.2 do not apply. This modification is unnecessary since CTS 4.6.2.1.e must be performed on the same frequency as the 10 CFR 50 Appendix J Testing Program Plan. The provision that B

ADMINISTRATIVE

A.11 (cont'd) Specification 4.0.2 does not apply to the 10 CFR 50 Appendix J Testing Program is specified in CTS 6.8.4.f and inherent in ITS 5.5.12, and therefore, its removal is considered administrative. B

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 In moving the primary containment structural integrity requirements to ITS 3.6.1.1, the Primary Containment OPERABILITY LCO (refer to Discussion of Change A.8 above), the allowed Completion Time of 1 hour becomes applicable for structural conditions not in compliance with requirements. This allowed time to restore compliance before requiring a plant shutdown is less than the current 24 hours as specified in the CTS 3.6.1.4 Action. This conservatively brings the allowed times for restoration for a loss of containment structural integrity into agreement with a loss of primary containment OPERABILITY. The potential confusion in applying the appropriate restoration time is thereby eliminated. This change is more restrictive on plant operations.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LD.1 The Frequencies for performing CTS 4.6.2.1.e.2 and 4.6.2.1.f (proposed SR 3.6.1.1.2 and SR 3.6.1.1.3, respectively) have been extended from each refueling outage (currently 18 months) to 24 months to facilitate a change to the NMP2 refuel cycle from 18 months to 24 months. The proposed change will allow the normal 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 4.0.2 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 4.0.2 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. Reviews of historical maintenance

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) 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 small. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

"Specific"

L.1 The special reporting requirements associated with CTS 4.6.1.4.2 are deleted. Instead, reporting will be governed by the requirement of 10 CFR 50.73. CTS 4.6.1.4.2 defines special reporting requirements when abnormal degradation of the primary containment structure is detected during visual inspection (CTS 4.6.1.4.1). The ITS implements 10 CFR 50, Appendix J, Option B, which has no special reporting requirements in this instance. ITS 5.5.12, "10 CFR 50 Appendix J Testing Program Plan," directly references Regulatory Guide 1.163 which provides guidance on implementing the requirements of 10 CFR 50, Appendix J, Option B. Per ANSI/ ANS 56.8-1994 (which is referenced in Regulatory Guide 1.163), the intent of the visual inspection is to identify evidence of structural deterioration that might affect either the containment structural integrity or leak tightness prior to a Type A leakage test. ANSI/ANS 56.8 further states that failure of any Type A, B, or C leakage test must be assessed for reporting required by 10 CFR 50.72 and 10 CFR 50.73. In essence, reporting will now only be required when degradation of the primary containment structure is significant enough to warrant an LER per 10 CFR 50.73. This is acceptable because the special reporting requirements of CTS 4.6.1.4.2 are not necessary to assure operation in a safe manner and there is no requirement for the NRC to approve the report. Therefore, this change has no impact on the safe operation of the plant. Deletion of the above reporting requirement (CTS 4.6.1.4.2) reduces the administrative burden on the plant and allows efforts to be concentrated on restoring the primary containment structural integrity to acceptable limits.

L.2 In the ITS presentation (refer to Discussion of Change A.9 above), drywell-to-suppression chamber bypass leakage outside limits (proposed SR 3.6.1.1.2) will result in declaring the Primary Containment inoperable. ITS 3.6.1.1 ACTIONS for these conditions require commencing a shutdown to MODES 3 and 4 if the leakage problem is not corrected within 1 hour. CTS 3.6.2.1 Action e only restricts heating up reactor coolant above 200°F (i.e., entry into MODE 3). With the drywell-to-suppression chamber bypass leakage outside of limits in

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) MODE 1, 2, or 3, CTS 3.6.2.1 does not provide actions. Since drywell-to-suppression chamber leakage are attributes of maintaining Primary Containment Integrity (in ITS terminology, primary containment OPERABILITY), a 1 hour allowed outage time is provided for this condition consistent with the primary containment is inoperable. This change will provide consistency in ITS ACTIONS for the various primary containment degradations. With primary containment OPERABILITY lost, the risk associated with continued operation for a short period of time could be less than that associated with an immediate plant shutdown. This change to CTS 3.6.2.1 is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which continued operation is allowed and primary containment is inoperable.

L.3 CTS 4.6.2.1.d requires a visual inspection of the exposed accessible interior and exterior surfaces of the suppression chamber every 18 months. No specific acceptance criteria are specified. CTS 4.6.1.4.1 requires the same inspection at a schedule in accordance with the 10 CFR 50 Appendix J Testing Program Plan (i.e., at a Frequency that is nominally 40 months). CTS 4.6.1.4.1 does specify acceptance criteria. 10 CFR 50 Appendix J also requires a visual inspection prior to performing a Type A test, and if structural deterioration that could affect structural integrity or leak-tightness is found, the Type A test shall not be performed until the problem is repaired. Therefore, the specific 18 month Frequency in CTS 4.6.2.1.d has been deleted, which effectively changes the actual test requirement Frequency from 18 months to the Frequency specified in CTS 4.6.1.4.1 and 10 CFR 50 Appendix J. An historical review has been performed and determined that while there is no specific acceptance criteria for this Surveillance, it has never failed the acceptance criteria of CTS 4.6.1.4.1 or 10 CFR 50 Appendix J. Therefore, it is acceptable to essentially extend the Frequency of this specific Surveillance to a Frequency already approved by the NRC in the CTS and in regulations. B

L.4 The requirement in CTS 4.6.2.1.e.1 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. The test schedule is normally every outage requiring a Type A test. 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 4.6.2.1.e.2. 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) B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd) when one test fails. In addition, an historical review has shown that this Surveillance has never failed since full power operation has commenced. Therefore, this change is considered acceptable. B

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

L.3 In reference to immediately maintaining an air lock door closed, the word "maintain" in CTS 3.6.1.3 Actions a.1 and c is changed to "verify" and 1 hour is allowed to complete the verification in ITS 3.6.1.2 (Required Actions A.1 and C.2). This change is acceptable because the level of degradation associated with the CTS Actions is no worse than that allowed for Primary Containment Integrity (CTS 3.6.1.1) not maintained. CTS 3.6.1.1 (ITS 3.6.1.1) allows the primary containment to be inoperable for 1 hour. Also, the primary containment air lock doors are normally closed except for entry and exit. Therefore, the probability that the OPERABLE air lock door is open is low during the 1 hour period.

L.4 Notes have been added to ITS 3.6.1.2 Required Actions A.3 and B.3 to allow administrative means to be used to verify locked closed OPERABLE air lock doors in high radiation areas or areas with limited access due to inerting. The air locks are initially verified to be in the proper position and access to them is restricted during operation due to the high levels of radiation or since the containment is inerted. Therefore, the probability of misalignment of the air locks are acceptably small. Eliminating the physical door verification in areas of high radiation and inerting removes a risk to personnel safety. Also, not requiring access to areas of high radiation to verify proper containment air lock door alignment reduces exposure to plant personnel and is consistent with the As-Low-As-Reasonably-Achievable (ALARA) concept.

L.5 CTS 4.6.1.3.a.1 requires verifying the air lock door seal leakage rate is within limit once per 7 days when the air lock door is opened for multiple entries. The ITS will allow this test to be performed every 30 days (as described in Regulatory Guide 1.163, which is required to be met in ITS 5.5.12). This extension was recommended and approved by the NRC in Regulatory Guide 1.163, September 1995. A review of maintenance history has also shown that this test normally passes the leak rate test. Therefore, this test simply confirms Operability, and the extension does not negatively impact safety.

L.6 The Frequency for the air lock interlock test, CTS 4.6.1.3.c and Footnote † is proposed to be changed from prior to performing SR 4.6.1.3.a to 24 months in proposed SR 3.6.1.2.2. Typically, the interlock is installed after each refueling outage, verified OPERABLE with the Surveillance, and not disturbed until the next refueling outage. If the need for maintenance arises when the interlock is required, the performance of the interlock Surveillance would be required following the maintenance. In addition, when an air lock is opened during times the interlock is required, the operator first verifies that one door is completely shut before attempting to open the other door. Therefore, the

A.1

Specification 3.6.1.3

CONTAINMENT SYSTEMS

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

LIMITING CONDITIONS FOR OPERATION

LCO 3.6.1.3

3.6.3 Each primary containment isolation valve and reactor instrumentation line excess flow check valve shall be OPERABLE**. M.1

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 add proposed 2nd Applicability A.2

ACTION: add proposed Note 2 to ACTIONS add proposed Notes 3 and 4 to ACTIONS A.3

ACTIONS A and C

a. With one or more of the primary containment isolation valves inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 4 hours either: A.4 L.1

1. Restore the inoperable valve(s) to OPERABLE status, or A.5

2. Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position,* or

3. Isolate each affected penetration by use of at least one closed manual valve or blind flange.* or check valve with flow secured L.2 Required Action A.1 only

4. The provisions of Specification 3.0.4 are not applicable provided that within 4 hours the affected penetration is isolated in accordance with ACTION a.2 or a.3 above, and provided that the associated system is declared inoperable, if applicable, and the appropriate ACTION statements for that system are performed. A.6 A.3

NOTE 3 to ACTIONS

ACTION F Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. L.3

add proposed ACTION B

ACTION C

b. With one or more of the reactor instrumentation line excess flow check valves inoperable, operation may continue and the provisions of Specifications 3.0.3 and 3.0.4 are not applicable provided that within 4 12 hours either; A.6 L.4 B

1. The inoperable valve is returned to OPERABLE status, or A.5

2. The instrument line is isolated and the associated instrument is declared inoperable. A.3

NOTE 3 to ACTIONS

ACTION F Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. M.1

add proposed ACTION G

NOTE 1 to ACTIONS

* Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control. L.5

NOTE 2 to SR 3.6.1.3.2 and SR 3.6.1.3.3

**Locked or sealed closed valves may be opened on an intermittent basis under administrative control.

A.1

Specification 3.6.1.3

REACTOR COOLANT SYSTEM

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITIONS FOR OPERATION

LCO 3.6.1.3 3.4.7 Two main steam line isolation valves (MSIVs) per main steam line shall be OPERABLE with closing times greater than or equal to 3 and less than or equal to 5 seconds. A.8

SR 3.6.1.3.7

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3. L.5

ACTION: add proposed ACTIONS Note 1 A.2 B

add proposed ACTIONS Note 2

a. With one or more MSIVs inoperable: A.4

ACTION A

1. Maintain at least one MSIV OPERABLE in each affected main steam line that is open and within 8 hours, either: L.1

a) Restore the inoperable valve(s) to OPERABLE status, or A.5

b) Isolate the affected main steam line by use of a deactivated MSIV in the closed position. L.2

ACTION F 2. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

add proposed ACTION B

b. The provisions of Specification 3.0.4 are not applicable. A.6

L.3

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.7 4.4.7 Each of the above required MSIVs shall be demonstrated OPERABLE by verifying full closure between 3 and 5 seconds when tested pursuant to Specification 4.0.5.

A.1

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

Specification 3.6.1.3

PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITIONS FOR OPERATION

See Discussion of Changes for ITS: 3.6.1.1, "Primary Containment," in this section.

3.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2*, and 3.

ACTION:

Without PRIMARY CONTAINMENT INTEGRITY, restore PRIMARY CONTAINMENT INTEGRITY within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

L.10

SURVEILLANCE REQUIREMENTS

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

a. After each closing of each penetration subject to Type B testing, except the primary containment air locks, if opened following Type A or B test, by leak rate testing the seals in accordance with the 10 CFR 50 Appendix J Testing Program Plan.

and Not locked, sealed, or secured

Required Actions A.2 and C.2 and b. SR 3.6.1.3.2 — At least once per 31 days by verifying that all primary containment penetrations** not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in position, except as provided in Specification 3.6.3.

Note 1 to ACTIONS and Note 2 to SR 3.6.1.3.2

L.5

SR 3.6.1.3.2 Required Actions A.2 and C.2 — or check valve with flow secured

L.2

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

add Notes 1 and 2 to Required Action A.2 and C.2, and Note 1 to SR 3.6.1.3.2, SR 3.6.1.3.3

d. By verifying the suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

See Discussion of Changes for ITS: 3.6.1.1, in this section.

L.11

* See Special Test Exception 3.10.1

** Except valves, blind flanges, and deactivated automatic valves which are located inside the containment, and are locked, sealed, or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except such verification need not be performed when the primary containment has not been de-inerted since the last verification or more often than once every 92 days.

Not

L.10

B

Required Action A.2 and SR 3.6.1.3.3

L.5

add Note 2 to SR 3.6.1.3.3

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(A.1)

Specification 3.6.1.3

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT

PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITIONS FOR OPERATION

3.6.1.2 (Continued)

ACTION:

b. The measured combined leakage rate on a minimum pathway basis for all penetrations and all Primary Containment Isolation Valves, except for main steam line isolation valves* and valves which are hydrostatically leak tested, subject to Type B and C tests equaling or exceeding 0.60 La, or

CONDITION D

c. The measured combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves, or

CONDITION D/E

d. The measured leakage rate through any valve that is part of a potential bypass leakage pathway exceeding the limit specified in Table 3.6.1.2-1

(LA.3) purge valves only

Restore:

a. The overall integrated leakage rate to less than 1.0 La, and

b. The combined leakage rate on a minimum pathway basis for all penetrations and all Primary Containment Isolation Valves, except for main steamline isolation valves* and valves which are hydrostatically leak tested, subject to Type B and C tests to less than 0.60 La, and

Required Action D.1

c. The combined leakage rate for all containment isolation valves in hydrostatically tested lines which penetrate the primary containment to less than or equal to 1 gpm times the total number of such valves, and

Required Actions D.1 and E.1

d. The leakage rate to less than or equal to that specified in Table 3.6.1.2-1 for any valve that is part of a potential bypass leakage path.

(LA.3) purge valves only

(L.12)

extend Completion times from 1 hour to 4 hours for hydrostatically tested line leakage not on a closed system and for secondary containment bypass leakage, 8 hours for MSIV leakage, and 72 hours for hydrostatically tested line leakage on a closed system

(B)

see Discussion of Changes for ITS: 3.6.1.1, in this section.

* Exemption to Appendix J to 10 CFR 50

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A.1

Specification 3.6.1.3

CONTAINMENT SYSTEMS

PRIMARY CONTAINMENT

PRIMARY CONTAINMENT PURGE SYSTEM

LIMITING CONDITIONS FOR OPERATION

A.8

LCO 3.6.1.3

3.6.1.7 The drywell and suppression chamber 12-inch and 14-inch purge supply and exhaust isolation valves shall be OPERABLE and:

Note to SR 3.6.1.31

a. The 12-inch (2CPS*AOV105, 2CPS*AOV107, 2CPS*AOV109, 2CPS*AOV111) and 14-inch (2CPS*AOV104, 2CPS*AOV106, 2CPS*AOV108, 2CPS*AOV110) valves in the purge system supply and exhaust lines may be open for up to 135 hours per 365 days for VENTING or PURGING.* L.15

b. Purge system valves 2CPS*AOV105 (12-inch), 2CPS*AOV107 (12-inch), 2CPS*AOV109 (12-inch), and 2CPS*AOV110 (14-inch) shall be blocked to limit the opening to 70°. Purge system valve 2CPS*AOV111 (12-inch) shall be blocked to limit the opening to 60°. L.16

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3. L.5

ACTION: add proposed ACTIONS Note 1 A.2 add proposed ACTIONS Note 2 A.3 add proposed ACTIONS Note 4 L.15 B

ACTIONS A and B, ACTION F

a. With the drywell and suppression chamber purge supply and/or exhaust isolation valve(s) inoperable, or open for more than 135 hours per 365 days for other than pressure control, close the open valve(s); otherwise isolate the penetration(s) within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. M.2

L.12

ACTION E

b. With a drywell and suppression chamber purge supply and/or exhaust isolation valve(s) with resilient material seals having a measured leakage rate exceeding the limit of Surveillance Requirement 4.6.1.7.2, restore the inoperable valve(s) to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. L.17

add proposed Required Actions E.2 and E.3

ACTION F

Note to SR 3.6.1.3.1

* The 135 hour limit shall not apply to the use of valves 2CPS*AOV108 (14-inch) and 2CPS*AOV110 (14-inch), or 2CPS*AOV109 (12-inch) and 2CPS*AOV111 (12-inch), for primary containment pressure control, provided 2GTS*AOV101 is closed, and its 2-inch bypass line is the only flow path to the standby gas treatment system. L.15

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 This proposed change to the CTS 3.6.3, CTS 3.4.7, and CTS 3.6.1.7 Actions provides more explicit instructions for proper application of the Actions for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," the ITS 3.6.1.3 ACTIONS Note 2 ("Separate Condition entry is allowed for each penetration flow path") provides direction consistent with the intent of the existing Actions for inoperable isolation valves. It is intended that each inoperable penetration flow path is allowed a certain time to complete the Required Actions. Since this change only provides more explicit direction of the current interpretation of the existing specification, this change is considered administrative. B

A.3 The ITS 3.6.1.3 ACTIONS include Notes 3 and 4. These Notes facilitate the use and understanding of the intent for a system made inoperable by inoperable PCIVs, that the applicable ACTIONS for that system also apply. This requirement is currently located in CTS 3.6.3 Actions a.4 and b.2, but it does not cover all situations. Therefore, ITS 3.6.1.3 ACTIONS Note 3 has been added to cover all situations. ITS 3.6.1.3 ACTIONS Note 4 clarifies that these "systems" include the primary containment. With ITS LCO 3.0.6, this intent would not necessarily apply. In addition, Note 4 has been added to CTS 3.6.1.7 to ensure the proper actions are taken if purge valve leakage results in exceeding the overall Type A leakage limit. The clarification is consistent with the intent and interpretation of the existing Technical Specifications, and is therefore considered administrative. B

A.4 CTS 3.6.3 Action a and CTS 3.4.7 Action a.1 do not specify penetrations with one or two isolation valves. However, ITS 3.6.1.3 Condition A applies if the affected penetration has two valves, and only one is inoperable. This inherently ensures maintaining "at least one isolation valve OPERABLE." In the case of containment penetrations designed with only one isolation valve, the system boundary is considered an adequate barrier and the penetration is not considered "open" when the single isolation valve is open. This change is a presentation preference and is administrative in nature.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 CTS 3.6.3 Action a requires an inoperable PCIV to be restored or the affected penetration isolated in 4 hours. CTS 3.4.7 Action a also requires an inoperable MSIV (which is a PCIV) to be restored or the affected penetration isolated in 4 hours. ITS 3.6.1.3 Required Action A.1 allows 8 hours to isolate the affected penetration when an MSIV is inoperable, and ITS Required Action C.1 (second Completion Time) allows 72 hours to isolate the affected penetration when a PCIV is inoperable in a penetration with a closed system and only one PCIV. For the MSIVs, the additional 4 hours provides more time to restore the inoperable MSIV given the fact that MSIV closure will result in isolation of the affected main steam line and potential for a plant shutdown. The additional time is reasonable since the penetration can still be isolated using the other MSIV and the low probability of a main steam line break. For PCIVs in a penetration with a closed system and only one PCIV, they are either in a closed system, as specifically defined in NUREG-0800 (the Standard Review Plan), section 6.2.4, or they are in a penetration whose system piping communicates with the suppression pool and is expected to remain submerged during the accident (i.e., a closed system as defined in the USAR). The NRC has allowed this design for NMP2 and other BWRs and, while the reason these types of penetrations meet the requirements of the General Design Criteria (GDC) is not specifically described in the Standard Review Plan, they meet the GDC requirements for being classified as a closed system outside the containment because they satisfy "other defined bases" established by the NRC to meet the GDC requirements. The additional time is reasonable for the closed system valves since the intact piping or the water seal acts as the penetration isolation barrier and ensures that the primary containment boundary is maintained intact until another barrier can be established to isolate the penetration. This additional time also avoids the potential for a plant shutdown and provides time to repair the inoperable PCIV in lieu of isolating the penetration (which could result in an inoperable ECCS subsystem, since the water sealed PCIVs are only in ECCS penetrations).

L.2 CTS 3.6.3 Action a, CTS 3.4.7 Action a, and CTS 4.6.1.1.b list some, but not all, of the possible acceptable isolation devices that may be used to satisfy the need to isolate a penetration with an inoperable isolation valve. ITS 3.6.1.3 ACTIONS provide a complete list of acceptable isolation devices. Since the result of the ACTIONS continues to be an acceptably isolated penetration for continued operation, the proposed change does not adversely affect safe operation. Many penetrations are designed with check valves as acceptable isolation barriers. With forward flow in the line secured, a check valve is essentially equivalent to a closed manual valve. For those penetrations designed with check valves as acceptable isolation devices, the ITS provides an

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) equivalent level of safety. For penetrations not designed with check valves for isolation, the ITS does not affect the requirements to isolate with a closed deactivated automatic valve, closed manual valve, or blind flange. ITS ACTIONS allowing closed manual valves or check valves with flow secured also apply to isolating main steam lines, even though the design does not provide for these type of isolation devices. This change is simply a result of simplicity in providing a consistent presentation for all penetrations. While this apparent flexibility does not result in any actual technical change in the Technical Specifications, it is listed here for completeness.

L.3 In the event two or more valves in a penetration are inoperable, CTS 3.6.3 Action a, which requires maintaining one isolation valve OPERABLE, would not be met and an immediate shutdown would be required. ITS 3.6.1.3 ACTION B provides 1 hour prior to commencing a required shutdown. This proposed 1 hour period is consistent with the existing time allowed for conditions when the primary containment is inoperable. The proposed change will provide consistency in ACTIONS for these various primary containment degradations. This change to CTS 3.6.3 is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which continued operation is allowed and the capability to isolate a primary containment penetration is lost.

L.4 CTS 3.6.3 Action b allows 4 hours to either repair the inoperable excess flow check valve or isolate the associated instrument. ITS 3.6.1.3 Required Action C.1 has extended this time to 72 hours. In this event, a limiting event would still be assumed to be within the bounds of the safety analysis (the excess flow lines contain orifices and are approximately ¼ inch in diameter.) Allowing an extended restoration time, to potentially avoid a plant transient caused by the forced shutdown, is reasonable based on the probability of a EFCV line break event and does not represent a significant decrease in safety. 1 B

L.5 An allowance is proposed for intermittently opening, under administrative control, closed primary containment isolation valves, other than those currently allowed to be opened using CTS 3.6.3 LCO Footnote ** and Action Footnote *. The allowance is presented in ITS 3.6.1.3 ACTIONS Note 1, and in Note 2 to SR 3.6.1.3.2 and SR 3.6.1.3.3. Opening of primary containment penetrations on an intermittent basis is required for performing surveillances, repairs, routine evolutions, etc. Intermittently opening closed PCIVs is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the PCIV is open and the administrative controls established to ensure the affected penetration can be isolated when a need for primary containment isolation is indicated.

TECHNICAL CHANGES - LESS RESTRICTIVE

L.11 (cont'd) In addition, an allowance is proposed to allow verification of isolation devices that are locked, sealed, or otherwise secured to also be performed using administrative means. The allowance is presented in Note 2 to ITS Required Actions A.2 and C.2. Plant procedures control the operation of locked, sealed, or otherwise secured isolation devices; thus the potential for inadvertent misalignment of these devices after locking, sealing, or otherwise securing is low. In addition, the isolation devices were verified to be in the correct position prior to locking, sealing, or otherwise securing.

L.12 CTS 3.6.1.2 Action (Restore) c and d requires restoration of the leakage to within limits, but does not provide a finite Completion Time. However, since the leakage rate from the valves is considered in the current definition of PRIMARY CONTAINMENT INTEGRITY (CTS Definition 1.31) the restoration time of the CTS 3.6.1.1 Action, 1 hour, is applicable. In addition, if a purge supply valve with resilient seals is the reason the leakage is not within limits, CTS 3.6.1.7 Action b is required to be entered, and provides 24 hours to restore the leakage to within limits (however, since CTS 3.6.1.1 Action is more limiting, it will govern the total time to restore leakage). The times to restore the leakage have been modified in the ITS to be 4 hours for hydrostatically tested line leakage not on a closed system and for secondary containment bypass leakage paths (which includes purge supply valve leakage), excluding MSIVs (ITS 3.6.1.3 Required Action D.1, 1st and 2nd Completion Times), 8 hours for MSIVs (ITS 3.6.1.3 Required Action D.1, 3rd Completion Time), and 72 hours for valves in hydrostatically tested lines on a closed system (ITS 3.6.1.3 Required Action D.1, 4th Completion Time). In addition, the 4 hour and 8 hour times are consistent with the existing times allowed for other conditions when valves in hydrostatically tested lines, secondary containment, or MSIVs are inoperable. With one of the leakages not within limit, the risk associated with continued operation for a short period of time could be less than that associated with a plant shutdown, since the change provides more time to restore the leakage to within limits. This change is acceptable due to the low probability of an event that would require the leakage to be within limits during the short time in which continued operation is allowed with leakage outside the limits. In addition, for the hydrostatically tested lines on a closed system, the valves are either in a closed system as specifically defined in NUREG-0800, section 6.2.4, or are water sealed, and would not be expected to leak after the accident (i.e., a closed system as defined in the USAR). ITS 3.6.1.3 ACTIONS Note 4 will also require immediately taking the ACTIONS of ITS 3.6.1.1 (which reduces the time allowed to restore the leakage to within limits to 1 hour) if leakage results in the overall primary containment leakage rate acceptance criteria being

B B B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.12 (cont'd) exceeded. Therefore, assurance is provided that the currently listed leakage limits will not adversely impact primary containment Operability during the extended time allowed to restore the leakage.

L.13 The details relating to the Line Description and Termination Region for the potential bypass leakage paths in CTS Table 3.6.1.2-1 are proposed to be deleted. These details are not necessary to ensure the leakage rates through the potential bypass leakage paths are within limits. The requirements of ITS 3.6.1.3 (which require the valves to be Operable), SR 3.6.1.3.11 and SR 3.6.1.3.12 (which requires the leakage rates to be verified within limits), and Table 3.6.1.3-1 (which lists the specific valves and the leakage rate limits) are adequate to ensure the leakage rates are maintained within limits. Therefore, these details have not been included in ITS Table 3.6.1.3-1.

L.14 CTS Table 3.6.1.2-1 footnote * states that for certain valves in potential bypass leakage paths, the leakage through each penetration shall be that of the valve with the highest rate in that penetration. ITS Table 3.6.1.3-1 footnote (a) will allow the leakage through the penetration to be the actual pathway leakage, provided the penetration is isolated by one closed and de-activated automatic valve, closed manual valve, or blind flange. The reason for assuming the pathway is maximum pathway leakage is to account for a single failure not closing one of the two valves in the penetration. However, if the penetration is already isolated by one of the methods described above, then a single failure cannot occur. Therefore, it is acceptable to assume the leakage through the penetration is the actual leakage through the valve that is isolating the penetration. If the penetration is isolated by both PCIVs, then the leakage through the penetration is the lesser leakage rate of the two PCIVs. This allowance is provided in the ISTS Bases for the secondary containment bypass leakage ACTION (ITS 3.6.1.3 ACTION D.1 Bases) and the associated Surveillance Requirement (proposed SR 3.6.1.3.11).

L.15 CTS 3.6.1.7 limits the time the 12 inch and 14 inch purge valves can be open to 135 hours per 365 days for PURGING OR VENTING. Footnote * to CTS 3.6.1.7 modifies the restriction to allow the purge valves to be open for an unlimited amount of time for primary containment pressure control, provided 2GTS*AOV101 is closed (which isolates the 20 inch line to the SGT System) and the 2 inch bypass line is the only flow path to the SGT System. The ITS does not include the time limitations, and replaces them with specific criteria for opening. The time limits were based on engineering judgement and/or early plant operating experience, and not based on any analytical requirement. The proposed limits on when the purge valves are permitted to be open, provided in the Note to proposed SR 3.6.1.3.1, will ensure appropriate

TECHNICAL CHANGES - LESS RESTRICTIVE

L.15 (cont'd) controls. The Note will continue to allow the purge valves to be open for inerting, deinerting, and pressure control, and will now allow the purge valves to also be open for ALARA or air quality considerations for personnel entry, as well as for Surveillances that require the purge valves to be open. Thus, use of the purge valves will continue to be minimized and limited to safety related reasons. The operating history indicates that these valves are only opened for the specified reasons and for cumulative periods that are generally less than the current allowed cumulative times. In addition, these valves are fully qualified to close in the required time under accident conditions to isolate the affected penetrations.

L.16 The requirement in CTS 3.6.1.7.b and CTS 4.6.1.7.1 to verify the primary containment purge valves with resilient seals are blocked to limit their opening to 60° or 70°, as applicable, has been deleted. The limits on the opening ensure the valves will close during a design basis accident (LOCA) to minimize the radiological consequences to within the limits of 10 CFR 100. These blocking devices are permanently installed devices located on the actuator and will require a design change to increase or decrease the current limits. The NMPC Design Control Process and Maintenance Program will ensure the blocking devices are set properly, and therefore, a requirement in the Technical Specifications is not necessary. These settings are not affected by drift, and therefore, if set properly there is no reason to expect a change in the settings. If maintenance was performed on the valve and the actuator was disassembled, the installation instructions will require the blocking devices settings to be verified.

L.17 The requirement in CTS 3.6.1.7 Action b to restore the leakage rate of the inoperable containment purge valve(s) with resilient seals has been changed to allow the isolation of the affected penetration and to continue operations without a requirement to restore the associated valves (ITS 3.6.1.3 Required Action E.1). The allowance provided must use at least one isolation barrier that cannot be adversely affected by a single failure such as a closed and de-activated automatic valve closed, manual valve, or blind flange. This ensures that a gross breach of the containment does not exist and is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. This flexibility is provided as long as this isolation is verified every 31 days (ITS 3.6.1.3 Required Action E.2) and the purge valve leak rate test is performed every 92 days if a purge exhaust valve with a resilient seal is used to perform the isolation (ITS 3.6.1.3 Required Action E.3). These actions assure that the penetration will not leak in excess of limits should an accident occur while operating, and this alleviates the need to shutdown the facility. This new flexibility is acceptable since the valve design allows individual leakage testing

TECHNICAL CHANGES - LESS RESTRICTIVE

L.17 (cont'd) of each purge valve with resilient seal (design permits imposing a back pressure on the outboard purge valves) so that the containment penetration may be isolated by a qualified valve as close as possible to the containment. If both valves are leaking in excess of the limit, a manual valve or blind flange may be used. In addition, in all cases, the actual leakage from the purge valves is also evaluated in accordance with overall leakage limit as required by ITS 3.6.1.3 ACTIONS Note 4. If the limit is exceeded due to the actual purge valve leakage, ITS 3.6.1.1 ACTION A will require leakage to be restored to within limits within one hour. Therefore, the proposed actions will ensure the actual leakage is within the limits of the safety analysis.

L.18 The surveillance frequency of CTS 4.6.1.7.2 (the leakage rate test of primary containment purge valves with resilient seals) is proposed to be extended from 92 days to 184 days and once within 92 days after opening the valve in proposed SR 3.6.1.3.6. The current 92 day frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened) and since the valves are opened during the operating cycle for containment pressure control and to comply with the Inservice Test Program. The surveillance test history indicates that the valves normally pass the leakage limit a the current 92 day frequency. Since the failure mechanism of the seal is a result of cycling the valve, there is no additional need to perform the test at the current frequency if the valves are not cycled. Therefore, based on the surveillance test history and the failure mechanism of the resilient seals, the proposed change is adequate to ensure leakage is maintained within the limit.

L.19 CTS 3.6.5.3 Action a.1 requires suspension of PURGING and VENTING (except when the containment purge full flow line to the SGT System is isolated as allowed by Footnote **) within 30 minutes when one SGT subsystem is inoperable and CTS 3.6.5.3 Action b.1 requires suspension of PURGING, VENTING, or pressure control (with no time specified to suspend the operations) when both SGT subsystems are inoperable. In the ITS, the Note to proposed SR 3.6.1.3.1, which allows the purge valves to be open under certain conditions, will include the SGT requirements of CTS 3.6.5.3 Actions a.1 (including Footnote **) and b.1. If the purge valves are open when not allowed by the Note, ITS 3.6.1.3 ACTION B will be required to be entered as the purge valves would be considered inoperable. ACTION B allows 1 hour to isolate the penetration. This proposed 1 hour period is consistent with the existing time allowed for conditions when the primary containment is inoperable. The proposed change will provide consistency in ACTIONS for these various containment degradations. This is acceptable due to the low probability of an event that could pressurize the primary containment during the

TECHNICAL CHANGES - LESS RESTRICTIVE

L.19 (cont'd) short time in which continued operation is allowed with the SGT System inoperable. In addition, the SGT Specification (CTS 3.6.5.3 and ITS 3.6.4.3) would also be requiring the unit to be shut down when both SGT subsystems are inoperable.

A.1

Specification 3.6.1.7

CONTAINMENT SYSTEMS

SUPPRESSION CHAMBER/DRYWELL VACUUM BREAKERS

SURVEILLANCE REQUIREMENTS add proposed Note 1 to SR 3.6.1.7.1 L.4

4.6.4 Each suppression chamber/drywell vacuum breaker shall be: add proposed Note 2 to SR 3.6.1.7.1 A.4 B

SR 3.6.1.7.1 a. Verified closed at least once per 7 days. 14 L.2

b. Demonstrated OPERABLE:

SR 3.6.1.7.2 1. At least once per 31 days and within 2 hours after any discharge of steam to the suppression chamber from the safety/relief valves, by cycling each vacuum breaker through at least one complete cycle of full travel. 12 L.3

2. At least once per 31 days by verifying the position indicator(s) OPERABLE by observing expected valve movement during the cycling test.* L.1 LD.1

3. At least once per 18 months by; 24

SR 3.6.1.7.3 a) Verifying the opening setpoint, from the closed position, to be less than or equal to 0.25 psid, and LA.2

b) Verifying the position indicators OPERABLE by performance of a CHANNEL CALIBRATION. L.1

L.1

* Observation of expected valve movement during cycling test will be accomplished for the purposes of this surveillance by observing valve position indicators in the control room.

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ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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)). 1 B

A.2 This proposed change to CTS 3.6.4 Action b Note provides more explicit instructions for proper application of the Actions for Technical Specification compliance. In conjunction with the proposed Specification 1.3, "Completion Times," the ITS 3.6.1.7 Conditions B and C Note ("Separate Condition entry is allowed for each suppression chamber-to-drywell vacuum breaker line") provides direction consistent with the intent of the existing Actions for an inoperable vacuum breaker. It is intended that each inoperable vacuum breaker line is allowed a certain time to complete the Required Actions. Since this change only provides more explicit direction of the current interpretation of the existing specification, this change is considered administrative.

A.3 CTS 3.6.4 Action b requires that with one suppression chamber-to-drywell vacuum breaker open, the other vacuum breaker in the line must be verified closed within 2 hours. This essentially allows both vacuum breakers in a line to be open for two hours. ITS 3.6.1.7 Action C has been provided to specifically require one vacuum breaker to be closed within 2 hours if both vacuum breakers in one line are found to be open. The current requirement, if met, will effectively ensure one vacuum breaker in a line is closed within the same 2 hours. Therefore, this change is considered administrative.

A.4 A Note has been added to CTS 4.6.4.a, the Surveillance that verifies the vacuum breakers are closed. Note 2 to SR 3.6.1.7.1 has been added to clearly state that the vacuum breakers do not have to be closed when they are performing their intended function, which is to open to relieve vacuum. Since it is obvious that OPERABILITY is still being maintained, this addition is considered administrative. 1 B

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - LESS RESTRICTIVE

L.3 (cont'd) OPERABILITY of the vacuum breakers). In addition, this change is recommended by the NRC in Generic Letter 93-05, item 8.4. Therefore, this extension in the performance of this functional test following an SRV discharge is not safety significant.

L.4 CTS 4.6.4.a requires that the vacuum breakers be closed at all times; with no explicit allowance to be open when performing their intended function (i.e., when relieving vacuum), and no allowance for opening during performance of required Surveillances. ITS SR 3.6.1.7.1 Note 1 states that the vacuum breakers can be opened when performing required Surveillances. This addition provides specific ITS direction, which is consistent with the intent of maintaining "OPERABLE" vacuum breakers. This allowance will not affect the ability of the vacuum breaker to perform its intended functions of relieving vacuum or of providing an isolated containment barrier in the event of positive primary drywell pressure. Therefore, this change introduces no negative impact on safety.

A.1

Specification 3.6.2.1

CONTAINMENT SYSTEMS

DEPRESSURIZATION SYSTEMS

SUPPRESSION POOL

(See Discussion of Changes for ITS: 3.6.2.2 "Suppression Pool Water Level," in this section.)

SURVEILLANCE REQUIREMENTS

4.6.2.1 The suppression pool shall be demonstrated OPERABLE:

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

A.2

b. At least once per 24 hours in OPERATIONAL CONDITION 1 or 2 by verifying the suppression pool average water temperature to be less than or equal to 90°F, except:

M.3

B

SR 3.6.2.1.1

1. During testing that adds heat to the suppression pool verify the suppression pool average water temperature to be less than or equal to 105°F at least once per 5 minutes.

Required Action A.1

2. When suppression pool average water temperature is greater than or equal to 90°F, verify at least once per hour that:

a) Suppression pool average water temperature is less than or equal to 110°F, and

b) THERMAL POWER is less than or equal to 1% of RATED THERMAL POWER after suppression pool average water temperature has exceeded 90°F for more than 24 hours.

L.3

Required Action A.2

3. Following a scram with suppression pool average water temperature greater than 90°F, verify suppression pool average water temperature to be less than or equal to 120°F at least once per 30 minutes.

c. By verifying at least 20 suppression pool water temperature instrumentation channels* OPERABLE by performance of a:

L.2

1. CHANNEL CHECK at least once per 24 hours,
2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and
3. CHANNEL CALIBRATION** at least once per 18 months,

with the water high temperature alarm setpoints ≤ 90°F for 10 of the temperature instruments and ≤ 110°F for 10 of the temperature instruments.

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* At least one pair in each of 10 suppression pool sectors with the alarm setpoint alternating between adjacent sectors.

** Calibration excludes sensors; sensors comparisons shall be made in lieu of calibration.

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 CTS 3.6.2.1.a.2 appears to require the 90°F and 105°F limits (shown in CTS 3.6.2.1.a.2 and 3.6.2.1.a.2.a)) to apply at all times when in Operational Condition 1 or 2 (ITS MODE 1 or 2). However, these two limits actually apply when THERMAL POWER is > 1% RTP. This is shown by CTS 3.6.2.1.a.2.b), which states that 110°F is the limit when ≤ 1% RTP. Therefore, the ITS LCO for these two limits has been clarified to be at > 1% RTP (ITS LCOs 3.6.2.1.a and b), and the ACTIONS have been modified to only require power to be decreased to ≤ 1% RTP (ITS 3.6.2.1 ACTION B) in lieu of the CTS 3.6.2.1 Actions b, b.1, and b.2.a) to shutdown the unit to MODE 3 and MODE 4. Once THERMAL POWER is ≤ 1% RTP, the LCO is met if suppression pool temperature is ≤ 110°F, thus, a shutdown to MODE 3 and MODE 4 is not required, as stated in CTS LCO 3.0.2. As such, this change is considered a presentation preference, which is administrative. B B

A.3 These requirements (CTS 3.6.2.1.b, CTS 3.6.2.1 Action e, and CTS 4.6.2.1.d, e, and f), relating to the drywell-to-suppression chamber bypass leakage limit, have been moved to ITS 3.6.1.1, in accordance with the format of the BWR Standard Technical Specifications, NUREG-1433, Rev. 1. Any technical changes to these requirements will be addressed in the Discussion of Changes for ITS: 3.6.1.1.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 CTS 3.6.2.1.a.2.c) allows the suppression pool temperature to be increased to 120°F with the main steam isolation valves (MSIVs) closed following a scram. ITS 3.6.2.1 ACTION E, which requires reactor vessel depressurization to < 200 psig when pool temperature exceeds 120°F, does not depend upon if the MSIVs are open or closed. If pool temperature reaches 120°F, significant heat

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 (cont'd) could still be added to the suppression pool regardless of MSIV position and the Required Action is appropriate. Even with MSIVs open, there may be no heat rejection from the containment, as in the case of a loss of condenser vacuum. Applying the ACTIONS regardless of the status of the MSIVs does not introduce any operation that is not analyzed. This change is more restrictive on plant operations. In addition, the requirement in CTS 3.6.2.1.a.2.c) has been removed from the LCO and is now only in the ACTIONS. This is a human factors consideration.

M.2 The CTS Applicability for the 110°F limit (CTS 3.6.2.1.a.2.b)) is MODES 1, 2, and 3 with THERMAL POWER ≤ 1% RTP. The CTS Applicability for the 120°F limit (CTS 3.6.2.1.a.2.c)) is MODES 1, 2, and 3. However, the current ACTIONS for when temperature exceeds 110°F require scramming the reactor (CTS 3.6.2.1 Action b.2.b)), and for when temperature exceeds 120°F only requires a depressurization to < 200 psig (CTS 3.6.2.1 Action b.3), both of which are still MODE 3. In ITS 3.6.2.1 ACTIONS D and E, when temperature exceeds 110°F or 120°F, the unit must also be placed in MODE 4 within 36 hours. This is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1, and is an additional restriction on plant operation necessary to ensure the reactor is placed outside the MODES and specified conditions of Applicability when these suppression pool average temperature limitations are exceeded.

M.3 CTS 4.6.2.1.b requires the suppression pool average water temperature to be verified to be within limits once per 24 hours in Operational Condition 1 or 2 (ITS MODE 1 or 2). As a result, with the plant in MODE 3, verification of suppression pool average water temperature is not required by the CTS. ITS SR 3.6.2.1.1 requires suppression pool average temperature to be verified to be within applicable limits once per 24 hours. The Applicability of ITS 3.6.2.1 is MODES 1, 2, and 3 and ITS SR 3.0.1 requires SRs to be met during MODES or other specified conditions in the Applicability for the individual LCO. Therefore, ITS SR 3.6.2.1.1 is required to be verified in MODES 1, 2, and 3. Expanding the applicability for performance of the suppression pool average temperature verification represents an additional restriction on plant operation necessary to help ensure containment conditions assumed in the safety analyses are satisfied. B

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

None

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 The CTS 3.6.2.1 Action b.2 details of how to reduce suppression pool temperature to within the limits (by operating at least one residual heat removal loop in the suppression pool cooling mode) are to be removed from the Technical Specifications. Methods for reducing suppression pool temperature to within limits are part of a coordinated response to an unplanned event governed by plant procedures. This detail of how to reduce suppression pool temperature to within limits is not necessary to ensure restoration of suppression pool temperature in a timely manner. The Required Actions of Condition D of ITS 3.6.2.1 ensure the unit is placed in a non-applicable MODE if the suppression pool temperature is not reduced to within limits. In addition, with the unit in a non-applicable MODE, the requirements of ITS LCO 3.0.4 ensure that suppression pool temperature is reduced to within limits prior to entering an applicable MODE.

L.2 The suppression pool temperature instrumentation specified in CTS 3.6.2.1 Actions c and d, and CTS 4.6.2.1.c does not necessarily relate directly to the OPERABILITY of the system. The BWR Standard Technical Specifications, NUREG-1434, does not specify indication-only equipment to be OPERABLE to support OPERABILITY of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indications and monitoring instrumentations are addressed by plant operational procedures and policies. Suppression pool temperature instrumentation is required to be OPERABLE to satisfy the suppression pool temperature verification Surveillance Requirement (proposed SR 3.6.2.1.1). If the suppression pool temperature instrumentation is inoperable, then the Surveillance Requirement cannot be satisfied and the appropriate actions must be taken for suppression pool temperature not within limits in accordance with the ACTIONS of ITS 3.6.2.1. As a result, the requirements for the suppression pool temperature instrumentation are adequately addressed by the requirements of ITS 3.6.2.1 and SR 3.6.2.1 and are proposed to be deleted from Technical Specifications.

L.3 When suppression pool temperature is > 90°F and ≤ 110°F, and power is > 1% RTP, ITS LCO 3.6.2.1.a is not being met. ITS 3.6.2.1 Required Action A.1 requires verification of suppression pool temperature once per hour in this condition. In the event power is < 1% RTP, the LCO is being met (ITS LCO 3.6.2.1.c) and proposed SR 3.6.2.1.1 verification of temperature every 24 hours is sufficient. When power is ≤ 1% RTP, the plant is essentially shut down, which is the action required should suppression pool temperature increase to > 110°F. Knowledge of current power level is an

TECHNICAL CHANGES - LESS RESTRICTIVE

L.3 (cont'd) inherent requirement for the operator at all times. Therefore, there is minimal significance to removing the 30 minute suppression pool verification when > 90°F but ≤ 110°F (in CTS 4.6.2.1.b.3) and hourly power level verification (in CTS 4.6.2.1.b.2.b)) in those conditions.

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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)). (B)

A.2 The CTS 3.6.2.2 Action b, footnote * requirement that if unable to attain Cold Shutdown when two or more RHR subsystems are inoperable, then maintain reactor coolant temperature as low as practical by use of alternate heat removal methods is deleted since it provides unnecessary duplication of the ACTIONS, contains no additional restrictions on the operation of the plant, and in fact, could be interpreted as a relaxation of the requirements to achieve MODE 4. The Action to be in MODE 4, which is modified by the footnote, adequately prescribes the requirement to make efforts to "maintain reactor coolant temperature as low as practical" (i.e., the duplicative requirement of the footnote). If conditions are such that MODE 4 cannot be attained, the Action remains in effect, essentially requiring efforts to reach MODE 4 to continue. Elimination of the footnote reflects an administrative presentation preference.

A.3 CTS 4.6.2.2.a requires verification that each suppression pool spray valve in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position. The suppression pool spray function is manually actuated (requiring reposition of valves and starting of the RHR pump by the operator). In the CTS, this is recognized and interpreted that "in the correct position" allows the valves to be in a non-accident position provided they can be realigned to the correct position. In the ITS, the words "in the correct position" mean that the valves must be in the accident position, unless they can be automatically aligned on an accident signal. If so, then they can be in the non-accident position. Thus, for RHR suppression pool spray the additional words "or can be aligned to the correct position" have been added in proposed SR 3.6.2.4.1 to clarify that it is permissible for this systems' valves to be in the non-accident position and still be considered OPERABLE. In addition, since there are no automatic valves, for the suppression pool spray mode, the reference to check automatic valves has been deleted. Since these are the current requirements, these changes are considered administrative.

RELOCATED SPECIFICATIONS

None

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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)). 1 B

A.2 CTS 3.6.6.2 Applicability footnote *, which provides a cross reference to CTS 3.10.5, has been deleted. The format of the proposed Technical Specifications does not include providing cross references. Proposed LCO 3.0.7 adequately prescribes the use of the Special Operations LCOs without such references. Therefore, the existing reference in the CTS 3.6.6.2 Applicability footnote * to the Special Test Exception of CTS 3.10.5 serves no functional purpose, and its removal is an administrative change. In addition, the exception was only permitted during the startup test program, which is now complete.

A.3 The CTS 3.6.6.2 Applicability and the Action for failing to meet the LCO are not consistent. ITS 3.6.3.2 revises the presentation of the ACTIONS to be consistent. The ITS 3.6.3.2 ACTION B only requires shutdown to 15% RTP. Below 15% RTP, the Applicability is exited and the ACTIONS are no longer required (in accordance with CTS and ITS LCO 3.0.1 and LCO 3.0.2). Since the CTS 3.6.6.2 Action can also be suspended at 15% RTP for the same reason, the change is considered administrative.

A.4 CTS 4.6.6.2 requires oxygen concentration in primary containment to be verified within limit prior to entering the Applicability of CTS 3.6.6.2 (within 24 hours after THERMAL POWER is greater than 15% of RTP). This redundant requirement is deleted. CTS 4.0.4 and ITS SR 3.0.4 require surveillances to be performed prior to entering the Applicability of an LCO. Therefore, this requirement does not need to be repeated as a separate Surveillance Frequency and its deletion is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 The definition of SECONDARY CONTAINMENT INTEGRITY in CTS 3.6.5.1 has not been included in the ITS. It is replaced with the requirement for secondary containment to be OPERABLE. This was done because of the confusion associated with these definitions compared to its use in the respective LCO. Therefore, the references in CTS 3.6.5.1 to SECONDARY CONTAINMENT INTEGRITY are replaced with the requirement for secondary containment to be OPERABLE. The change is editorial in that all the requirements of CTS 3.6.5.1 are specifically addressed in the ITS and associated Bases for the Secondary Containment (3.6.4.1), the Secondary Containment Isolation Valves (3.6.4.2), and Standby Gas Treatment System (3.6.4.3). Therefore, the change is a presentation preference adopted by the BWR Standard Technical Specifications, NUREG-1434, Rev. 1.

A.3 The CTS 4.6.5.1.b.2 requirement to verify that one door in each access is closed has been modified to require one door in each access opening to be closed in proposed SR 3.6.4.1.3. The NMP2 design includes more than two doors on some of the accesses. The current NMP2 interpretation of this requirement is that for these accesses, there are multiple access openings, and each access opening must have one door closed. Therefore, this change is a clarification of current practice, and as such, is administrative in nature. B B

A.4 CTS 4.6.5.1.b.3, relating to the position of secondary containment isolation valves, has been moved to ITS 3.6.4.2, "Secondary Containment Isolation Valves," in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. Any technical changes to this requirement will be discussed in the Discussion of Changes for ITS: 3.6.4.2.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 An allowance is proposed for intermittently opening closed secondary containment isolation valves under administrative control as is allowed in the existing primary containment Technical Specifications (CTS 3.6.3) and in ITS 3.6.1.3. The administrative controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. The allowance is presented in ITS 3.6.4.2 ACTIONS Note 1 and SR 3.6.4.2.1 Note 2. Opening of secondary containment penetrations on a intermittent basis is required for many of the same reasons as primary containment penetrations and the potential impact on consequences is less significant. The proposed allowance is acceptable due to the low probability of an event that could release radioactivity to the secondary containment during the short time in which the SCIV is open and the administrative controls established to ensure the affected penetration can be isolated when a need for secondary containment isolation is indicated. B

L.2 In the event both valves in a penetration are inoperable in an open penetration, the CTS 3.6.5.2 Action, which requires maintaining one isolation valve OPERABLE, would not be met and an immediate shutdown would be required. ITS 3.6.4.2 ACTION B provides 4 hours prior to commencing a required shutdown. This proposed 4 hour period is consistent with the existing time allowed for conditions when the secondary containment is inoperable. The proposed change will provide consistency in ACTIONS for these various secondary containment degradations. This change to CTS 3.6.5.2 is acceptable due to the low probability of an event requiring the secondary containment during the short time in which continued operation is allowed and the capability to isolate a secondary containment penetration is lost.

L.3 CTS 4.6.5.2.a is proposed to be deleted. Any time the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. After restoration of a component that caused a required SR to be failed, ITS SR 3.0.1 requires the appropriate SRs (in this case SR 3.6.4.2.2) to be performed to demonstrate the OPERABILITY of the affected components. Therefore, explicit post maintenance Surveillance Requirements in CTS 4.6.5.2 are not required and have been deleted from the Technical Specifications.

L.4 The requirement to perform CTS 4.6.5.2.b during COLD SHUTDOWN or REFUELING has not been included in proposed SR 3.6.4.2.3. The proposed Surveillance (for a functional test of each secondary containment isolation valve) does not include the restriction on plant conditions. All isolation valves

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd) can be adequately tested in other than Cold Shutdown or Refueling, without jeopardizing safe plant operations. The control of the plant conditions appropriate to perform the test is an issue for procedures and scheduling, and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction. As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specification Surveillances that do not dictate plant conditions for the Surveillance.

L.5 The phrase "actual or," in reference to the isolation test signal in CTS 4.6.5.2.b, has been added to proposed SR 3.6.4.2.3, which verifies that each SCIV actuates on an automatic isolation signal. This allows satisfactory automatic SCIV isolations for other than Surveillance purposes to be used to fulfill the Surveillance Requirement. Operability is adequately demonstrated in either case since the SCIV itself cannot discriminate between "actual" or "test" signals.

L.6 CTS 4.6.5.1.b.3 requires verification that certain secondary containment penetrations are isolated. An allowance is proposed to allow the verification of the isolation devices used to isolate the penetrations in high radiation areas to be verified by use of administrative controls. The allowance is presented in ITS 3.6.4.2 Required Action A.2 Note and SR 3.6.4.2.1 Note 1. This is acceptable since the isolation devices are initially verified to be in the proper position and access to them is restricted during operation due to the high levels of radiation in the area. Therefore, the probability of misalignment of the isolation devices is acceptably small. If for some reason these devices are opened (e.g., maintenance), the associated procedure or work package would require their closure after work is completed. The Required Action or Surveillance may be performed by reviewing that no work was performed in the associated radiation area since the isolation device was closed or if work was performed in that area that the closure was verified upon completion of the work if the valve was opened.

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
<DOC L.3> <3.6.1.7 Act a> B. ~~NOTE~~ Only applicable to penetration flow paths with two PCIVs. ~~One or more penetration flow paths with two PCIVs inoperable except for purge valve leakage not within limit.~~ (or more) (due to) (17) (3)	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour AND 72 hours for EFCVs and penetrations with a closed system (5) TSTF-30 change not shown
<3.6.3 Act a> <3.6.3 Act b> <4.6.1.1.b> <DOC L.11> C. ~~NOTE~~ Only applicable to penetration flow paths with only one PCIV. ~~One or more penetration flow paths with one PCIV inoperable.~~ (3) except due to leakage not within limit	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. AND (TSTF-269) (5) C.2 ~~NOTE~~ (1) Isolation devices in high radiation areas may be verified by use of administrative means.	~~24~~ hours (except for access flow check valves (EFCVs) and penetrations with a closed system) (5) 2. Isolation devices that are locked, sealed, or otherwise secure & may be verified by use of administrative means.
	Verify the affected penetration flow path is isolated.	Once per 31 days
<3.6.1.2 Act c "with"> <3.6.1.2 Act d "with"> (3) D. One or more penetration flow paths with secondary containment bypass leakage rate not within limit.	D.1 Restore leakage rate to within limit.	4 hours for secondary containment bypass leakage (7)
<3.6.1.2 Act c "restore"> <3.6.1.2 Act d "restore"> MSIV leakage rate, or hydrostatically tested line leakage rate		AND 8 hours for MSIV leakage AND 72 hours for hydrostatically tested line leakage on a closed system

(continued)

(7) 4 hours for hydrostatically tested line leakage not on a closed system AND

<CTS>

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.1	NOTE Only required to be met in MODES 1, 2, and 3.	
	Verify each [ ] inch primary containment purge valve is sealed closed except for one purge valve in a penetration flow path while in Condition E of this LCO.	31 days
SR 3.6.1.3.2	NOTES 1. Only required to be met in MODES 1, 2, and 3. 2. Not required to be met when the 20 inch primary containment purge valves are open for pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open, provided the drywell [purge supply and exhaust] lines are isolated.	
	Verify each 20 inch primary containment purge valve is closed.	31 days

<LCO 3.6.1.7.a>
<LCO 3.6.1.7 "*" Footnote>
<DOC M.3>
<3.6.5.3 Act a.1>
<3.6.5.3 Act b.1>
<3.6.5.3 Act "**" Footnote>

and 14 inch

inerting/de-inerting

12 inch and 14

a) the Standby Gas Treatment (SGT) System is OPERABLE; or
b) the primary containment full flow line to the SGT System is isolated and one SGT subsystem is OPERABLE.

(continued)

13 INSERT TABLE 3.6.1.3-1 (cont'd)

Table 3.6.1.3-1 (page 2 of 2)
Secondary Containment Bypass Leakage Paths Leakage Rate Limits

VALVE NUMBER	PER VALVE LEAK RATE (SCFH)
2CPS*SOV119 2CPS*SOV120 2CPS*SOV121 2CPS*SOV122	0.625
2IAS*SOV164 2IAS*V448	0.9375
2IAS*SOV165 2IAS*V449	0.9375
2GSN*SOV166 2GSN*V170	(a)
2IAS*SOV166 2IAS*SOV184	(a)
2IAS*SOV167 2IAS*SOV185	(a)
2IAS*SOV168 2IAS*SOV180	(a)
2CPS*SOV132 2CPS*V50	(a)
2CPS*SOV133 2CPS*V51	(a)

18

(a) The combined leak rate for these penetrations shall be ≤ 3.6 SCFH. The assigned leakage rate through a penetration shall be that of the valve with the highest leakage rate in that penetration. However, if a penetration is isolated by one closed and de-activated automatic valve, closed manual valve, or blind flange, the leakage through the penetration shall be the actual pathway leakage.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS: 3.6.1.3 - PRIMARY CONTAINMENT ISOLATION VALVES

1. This bracketed requirement has been deleted because it is not applicable to NMP2. The following requirements have been renumbered, where applicable, to reflect this deletion.

2. The words "in MODES 1, 2, and 3" have been deleted from ITS 3.6.1.3 ACTION Note 4 since there are no PCIV leakage tests required in MODES other than MODES 1, 2, and 3 for NMP2 (i.e., there are no PCIVs required to be OPERABLE in MODES other than MODES 1, 2, and 3 that have specific leakage limits). In addition, ISTS SR 3.6.1.3.2 Note 1, ISTS SR 3.6.1.3.9 Note 1, ISTS SR 3.6.1.3.11 Note 1, and the ISTS SR 3.6.1.3.6 Note have been deleted for the same reason. The following Notes have been renumbered, if applicable, due to these Notes deletion.

3. The words inside the brackets have been modified to reflect the different types of leakage categories. Since there is more than one, the generic word "leakage" has been used in ISTS 3.6.1.3 Conditions A, B, and C. The PCIVs are required to be OPERABLE such that they are in the accident condition or can be automatically repositioned to the accident condition, and certain PCIVs have individual leakage limits. These leakage limits are in addition to the type A, B, and C limits required by LCO 3.6.1.1, Primary Containment OPERABILITY. If a type A, B, or C limit were exceeded due to an individual valve exceeding its specific leakage limit, ISTS 3.6.1.3 ACTIONS Note 4 would require the ACTIONS of LCO 3.6.1.1 to be taken (which require primary containment to be restored within 1 hour).

   The change was made to reflect that different compensatory actions are required depending upon the cause of the inoperability. In the NMP2 ITS, ACTION A is taken if the PCIV is inoperable for reasons other than leakage; ACTIONS D and E are required if the SRs for individual valve leakage limits are not met. Currently (in the ISTS), Condition A would only exempt purge valve leakage and secondary containment bypass leakage requirements and Condition C does not exempt any leakage requirements. If a MSIV or a hydrostatically tested valve was not meeting the leakage limits, Condition A or C, as applicable, would be entered and Required Action A.1 or C.1 would be required. These Required Actions allow the penetration to be isolated. However, isolating the penetration can be performed by using the leaking valve. This would not provide adequate compensatory measures to allow continued operation. When a MSIV or hydrostatically tested valve leakage is not within limits, Condition D should be entered. The Required Action for this Condition would require the leakage to be restored within limit in 4 hours, 8 hours, or 72 hours, as applicable, consistent with the time provided in Required Actions A.1 and C.1 to isolate the penetration. As discussed in the ISTS Bases, the leakage can be restored by isolating the penetration with a valve not exceeding the leakage limits. This is more restrictive than Required Actions A.1 and C.1, which allows isolation using the leaking valve. Condition B has also been modified to exclude leakage. This Condition is appropriate if the valve is in the incorrect position or will not close. As discussed above, the Required Action for Condition B would also allow the

3. (continued)

penetration to be isolated using the leaking valve if the bracketed phrase were not deleted. This change is also consistent with proposed TSTF-207, Rev. 3, except where plant specific differences apply or consistency errors were noted. B

4. The NMP2 design includes the drywell as part of the primary containment and the primary containment is inerted while operating, similar to the BWR/4 design. Therefore, changes have been made to the requirements which check proper position of isolation devices, similar to the BWR/4 ISTS (NUREG-1433).

5. The NMP2 design also includes EFCVs and TIPs, similar to the BWR/4 design. Therefore, ITS 3.6.1.3 Required Action C.1 Completion Time has been modified and ITS SR 3.6.1.3.4, SR 3.6.1.3.9, and SR 3.6.1.3.10 have been added, consistent with the BWR/4 ISTS (NUREG-1433). The following requirements have been renumbered, where applicable, to reflect the additions. In addition, the Completion Times have been modified to be consistent with proposed TSTF-30, Rev. 3, in lieu of approved TSTF-30, Rev. 2. B

6. Not used. B

7. The time provided in ISTS ACTION D to restore MSIV leakage and hydrostatically tested line leakage on a closed system to within limits has been changed. The Required Action for this condition would require the leakage to be restored within limit in 4 hours for secondary containment bypass leakage (no change), 4 hours for hydrostatically tested line leakage not on a closed system (no change), 8 hours for MSIV leakage, and 72 hours for hydrostatically tested line leakage on a closed system. The new 8 hour Completion Time for MSIV leakage is consistent with the time provided in Required Action A.1 to isolate the main steam line penetrations. The 72 hour Completion Time for hydrostatically tested line leakage on a closed system is deemed appropriate based in part on the approved generic change TSTF-30, Rev. 1, which provides a 72 hour Completion Time for single valve penetrations in a closed system. Some of the hydrostatically tested lines are on a closed system, while others are water sealed and remain that way after the accident. This water sealed design was reviewed and approved by the NRC, as documented in the original NMP2 SER and its supplements. This change is also consistent with proposed TSTF-207, Rev. 3, except where plant specific differences apply. B B B B B

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

9. Typographical/grammatical error corrected.

10. The words in ISTS 3.6.1.3 Condition I (ITS Condition G), "or during operations with a potential for draining the reactor vessel (OPDRVs)," have been deleted. There are no PCIVs required to be OPERABLE in the NMP2 ITS whose Applicability is only during OPDRVs. The only PCIVs required when not in MODES 1, 2, and 3 are the RHR shutdown cooling isolation valves, and their Applicability is MODES 4 and 5. This Condition is still applicable in MODES 4 and 5, which are the only MODES that OPDRVs can be performed. Therefore, the "during OPDRVs" Applicability is duplicative of the MODES 4 and 5 Applicability and has been deleted.

11. The acronym "OPDRVs" has been defined, consistent with the format of the ITS, since it is the first use of this term in this Specification.

12. The Appendix J testing requirements and associated acceptance criteria, or exemptions to applying leakage to that acceptance criteria, is adequately addressed in proposed SR 3.6.1.1.1, The deleted Notes (ISTS SR 3.6.1.3.9 Note 2 and ISTS SR 3.6.1.3.11 Note 2) serve no purpose. Additionally, the ITS 3.6.1.3 ACTIONS Note 4 ("Enter applicable Conditions...results in exceeding overall containment leakage rate acceptance criteria") provides appropriate and sufficient control to direct the proper ACTIONS should excessive leakage be discovered. In addition, these Notes were approved to be deleted from NUREG-1434, Rev. 1 per change package BWR-14, C.3, but apparently were not deleted. The BWR/4 ISTS (NUREG-1433) did delete the Note for the hydrostatically tested lines (NUREG-1433 SR 3.6.1.3.14).

13. The NMP2 secondary containment bypass leakage analysis does not assume a total combined leakage rate, but assumes a leakage rate through each individual leakage path. Therefore, ITS SR 3.6.1.3.11 has been modified to reflect this analysis. In addition, a new Table, ITS Table 3.6.1.3-1 has been added to provide the individual leakage rates, consistent with the current licensing basis. ITS SR 3.6.1.3.11 provides a reference to the Table, thus this is consistent with the intent of the ISTS (to specify the leakage rates in the Technical Specifications).

14. The 10 CFR 50 Appendix J Testing Program Plan has been added to Section 5.5, similar to TSTF-52. 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 the Current Licensing Basis and TSTF-52.

15. The current leakage rate limit for the MSIVs is on a per valve basis rather than on a total leakage rate limit through all four main steam lines. ITS SR 3.6.1.3.12 reflects the current licensing basis.

16. ISTS Condition E has been modified to only be applicable to the containment purge exhaust valves. While the containment purge supply valves also have resilient seals, these valves are also secondary containment bypass leakage path valves. Thus they are not currently allowed a 24 hour restoration time similar to the exhaust valves;

16. (continued)

they must be restored in 4 hours, consistent with other secondary containment bypass leakage path valves. In addition, due to this change, ISTS Required Action E.3 has also been modified to pertain to purge exhaust valves only.

17. The words in ISTS Conditions A and B Notes and the words in ISTS Condition B have been modified to state "two or more" in lieu of "two." Some penetration flow paths at NMP2 have more than two PCIVs. This was required by the NRC for some penetrations whose outside PCIV was not close enough to the primary containment. This change will ensure an LCO 3.0.3 entry is not required for this design and the appropriate actions are taken consistent with a plant with only two PCIVs per penetration flow path. This change is also consistent with proposed TSTF-207, Rev. 3 (It is noted that the BWR/6 ISTS markup provided in TSTF-207, Rev. 3 inadvertently left out the words "or more" in Condition B. The BWR/4 ISTS markup included these words in Condition B.) B

INSERT BWR/4 ISTS 3.6.1.8* (1)

<CTS>

3.6 CONTAINMENT SYSTEMS

3.6.1.8 Suppression Chamber-to-Drywell Vacuum Breakers

LCO 3.6.1.8 [Nine] suppression chamber-to-drywell vacuum breakers shall be OPERABLE for opening.

<LCO 3.6.4>

AND

[Twelve] suppression chamber-to-drywell vacuum breakers shall be closed, except when performing their intended function.

APPLICABILITY: MODES 1, 2, and 3.

<Appl 3.6.4>

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
<3.6.4 Act a> A. One required suppression chamber-to-drywell vacuum breaker inoperable for opening.	A.1 Restore one vacuum breaker to OPERABLE status.	72 hours
<INSERT ACTION B NOTE>		
<3.6.4 Act b> B. One suppression chamber-to-drywell vacuum breaker not closed.	B.1 Close the open vacuum breaker.	2 hours
<INSERT ACTION C> <3.6.4 Act a> <3.6.4 Act b> D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

* THIS BWR/4 SPECIFICATION INSERT WAS USED BECAUSE IT BEST REPRESENTED THE NMP2 DESIGN

Insert Page 3.6-24a

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS: 3.6.1.7 - SUPPRESSION CHAMBER-TO-DRYWELL VACUUM BREAKERS

1. A new Specification has been added, ITS 3.6.1.7. This Specification is from the BWR/4 ITS (NUREG-1433 ISTS 3.6.1.8), since the NMP2 design is similar to the BWR/4 design with regard to the vacuum breakers. Therefore, the BWR/4 LCO is used and any deviations from the BWR/4 ISTS are discussed.

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

3. The design to which the BWR/4 ISTS 3.6.1.8 was written required all the suppression chamber-to-drywell vacuum breakers to be closed, but did not require all the suppression chamber-to-drywell vacuum breakers to be Operable. Therefore, two separate LCO statements were provided. The NMP2 current licensing basis requires all the suppression chamber-to-drywell vacuum breakers to be Operable and closed. To more closely match the NMP2 design, only a single LCO statement is needed. This LCO statement requires each suppression chamber-to-drywell vacuum breaker to be Operable, with the requirement to be closed as part of the Operable requirement. This is consistent with the BWR/4 ISTS 3.6.1.7 LCO statement, which requires each reactor building-to-suppression chamber vacuum breaker to be Operable (in this LCO statement, closed is part of Operable). In addition, since the second part of the deleted LCO statement ("except when performing their intended function") is still needed to be included in the Specification, a second Note has been included in SR 3.6.1.7.1 providing this allowance. The location of the Note is also consistent with the BWR/4 ISTS SR 3.6.1.7.1. Also, ISTS 3.6.1.8 Condition A and SRs 3.6.1.8.2 and 3.6.1.8.3 have been modified to delete the word "required." A

4. The NMP2 design for the suppression chamber-to-drywell vacuum breakers has two vacuum breakers per line. With either vacuum breaker closed, the isolation capability of the line is maintained. Therefore, the ISTS 3.6.1.8 ACTIONS have been modified to reflect this design and the current licensing basis. The changes are as follows:

   a. Condition A has been modified to apply to one or both vacuum breakers inoperable for opening in the same line. The Required Action has also been modified to requiring restoring both vacuum breakers (if both are inoperable) to Operable status. These changes are consistent with the NUREG-1433 ISTS 3.6.1.7, ACTION C, which allows 72 hours to restore all vacuum breakers in one line to Operable status.

   b. A Note is included in Condition B to allow separate entry on a per line basis. This Note is consistent to the Note provided in NUREG-1433 ISTS 3.6.1.7.

   c. Condition B has been modified to apply to more than one vacuum breaker line, but only if one of the two vacuum breakers is closed (i.e., one vacuum breaker is not closed in one or more vacuum breaker lines). The time allowed to close the open vacuum breaker has been changed to 72 hours. With one of the two

<LTS>

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

<LCO 3.6.2.3>

LCO 3.6.2.3 Two RHR suppression pool cooling subsystems shall be OPERABLE.

<Appl 3.6.2.3>

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

<3.6.2.3 Act a>

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool cooling subsystem inoperable.	A.1 Restore RHR suppression pool cooling subsystem to OPERABLE status.	7 days
~~B.~~ C Required Action and associated Completion Time ~~of Condition A~~ not met. ~~OR~~ ~~B.~~ C	~~B.1~~ C Be in MODE 3. AND ~~B.2~~ Be in MODE 4.	12 hours 36 hours
B. Two RHR suppression pool cooling subsystems inoperable.	B.1 Restore one RHR suppression pool cooling subsystem to OPERABLE status.	8 hours

<3.6.2.3 Act a>

<3.6.2.3 Act b>

<3.6.2.3 Act b>

TSTF-230 B

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS: 3.6.2.3 - RHR SUPPRESSION POOL COOLING

1. The NMP2 design does not include any automatically actuated RHR suppression pool cooling valves. The RHR suppression pool cooling mode is manually actuated. Therefore, the word "automatic" in ITS SR 3.6.2.3.1 has been deleted.

2. Editorial change made to be consistent with other similar requirements in the ITS.

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

4. The NMP2 design only uses two of the three RHR pumps in the suppression pool cooling mode. Therefore, ISTS SR 3.6.2.3.2 has been modified to only require the "required" RHR pumps to be tested. This change is consistent with the use of the word "required" in the ITS.

5. A new Specification has been added, ITS 3.6.2.4. This Specification is from the BWR/4 ISTS (NUREG-1433 ISTS 3.6.2.4), since the NMP2 design is similar to the BWR/4 design with regard to RHR suppression pool spray. Therefore, the BWR/4 LCO is used and any deviations from the BWR/4 ISTS are discussed in the Justification for Deviations for ITS: 3.6.2.4.

6. The words "of Condition A or B" (as modified by TSTF-230) have been deleted to be consistent with all other similar Conditions in the ITS. The format of the ITS is not to use the term "of Condition X" in a Condition, when the Condition applies to all Conditions previous to it and it is the last Condition in the ACTIONS Table. B

<CTS>

3.6 CONTAINMENT SYSTEMS

3.6.3.1 Primary Containment Hydrogen Recombiners ~~(if permanently installed)~~ 1

<LCO 3.6.6.1>

LCO 3.6.3.1 Two primary containment hydrogen recombiners shall be OPERABLE.

<Appl 3.6.6.1>

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
<3.6.6.1 Act> <DOC L.1> A. One primary containment hydrogen recombiner inoperable.	A.1 ---NOTE--- LCO 3.0.4 is not applicable. --- Restore primary containment hydrogen recombiner to OPERABLE status.	30 days
<DOC L.2> B. Two primary containment hydrogen recombiners inoperable. 3	B.1 Verify by administrative means that the hydrogen and oxygen control function is maintained. 2 AND B.2 Restore one primary containment hydrogen recombiner to OPERABLE status.	1 hour AND ~~One~~ Once per 12 hours thereafter 6 B 7 days

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS: 3.6.3.1 - PRIMARY CONTAINMENT HYDROGEN RECOMBINERS

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

2. The proper plant specific information/nomenclature/value has been provided.

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

4. The Current NMP2 Licensing Basis does not include ISTS SR 3.6.3.1.2, which requires a visual examination of each primary containment hydrogen recombiner enclosure and verification that there is no evidence of abnormal conditions. CTS 4.6.6.1.a (ITS SR 3.6.3.1.1) and CTS 4.6.6.1.b.2 (ITS SR 3.6.3.1.2) require a Hydrogen Recombiner system functional test and a heater resistance to ground test, respectively. This CTS testing, which is maintained in the ITS, provides adequate periodic surveillance testing to ensure the Operability of the Hydrogen Recombiners. A review of the historical surveillance and maintenance data demonstrate there were no failures of the Hydrogen Recombiners since the issuance of the operating license (i.e., approximately 12 years) that would warrant the inclusion of visual examination of each primary containment hydrogen recombiner enclosure on a periodic basis to ensure the Operability of the hydrogen recombiner. Furthermore, a review of the vendor manual supports this position in that there are no vendor recommendations to perform such a visual examination. Accordingly, NMPC concludes that requiring a visual examination of each primary containment recombiner enclosure at periodic intervals is not necessary and ISTS SR 3.6.3.1.2 has not been included in the NMP2 ITS.

5. A new Specification has been added, ITS 3.6.2.2. This Specification is from the BWR/4 ISTS (NUREG-1433 ISTS 3.6.3.3), since the NMP2 design is similar to the BWR/4 design with regard to oxygen concentration requirement (NMP2 inerts the primary containment since the containment is a Mark II). Therefore, the BWR/4 LCO is used and any deviations from the BWR/4 ISTS are discussed in the Justification for Deviations for ITS: 3.6.3.2.

6. Typographical error corrected.

1 B

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.4.1.3	Verify each secondary containment access door is closed, except when the access opening is being used for entry and exit, then at least one door shall be closed.	31 days
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.
SR 3.6.4.1.5	Verify each SGT subsystem can maintain ≥ 0.25 inch of vacuum water gauge in the secondary containment for 1 hour at a flow rate ≤ 4000 cfm.	[18] months on a STAGGERED TEST BASIS.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, 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. The allowance in the CTS that both doors can be open during entry and exit has been deleted. Thus, the allowance in the ITS is not necessary. This is consistent with the same SR in NUREG-1433, Rev. 1. The NMP2 design with respect to the number of doors in an access opening is consistent with the BWR/4 design (2 doors per access opening), not the BWR/6 design (one door per access opening). B

3. ISTS SRs 3.6.4.1.4 and 3.6.1.4.5 are tests that ensure the Secondary Containment is Operable; the leak tightness of the Secondary Containment boundary is within the assumptions of the accident analyses. However, they are written in such a manner that they imply that if a SGT subsystem is inoperable, the SRs are failed ("Verify each standby as treatment (SGT) subsystem will/can..."). As stated above, this is not the intent of the SRs. Therefore, to ensure this misinterpretation cannot occur, the SRs have been rephrased to more clearly convey the original intent of the SRs, to verify the Secondary Containment is Operable. With the new wording, if a SGT subsystem is inoperable, SRs 3.6.4.1.4 and 3.6.4.1.5 will still be met and only the SGT System Specification, LCO 3.6.4.3, will be required to be entered. The SRs will still ensure each SGT subsystem is used (on a STAGGERED TEST BASIS) to perform the SRs.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Design Basis Accident (DBA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. Additionally, this structure provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions.

The isolation devices for the penetrations in the primary containment boundary are a part of the primary containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. Primary containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks";

c. All equipment hatches are closed; and

d. The pressurized sealing mechanism associated with a penetration is OPERABLE, except as provided in LCO 3.6.1.4.

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 10 CFR 50, Appendix J, (Ref. 3), as modified by approved exemptions. Failure to meet air lock leakage testing (SR 3.6.1.2.1 and SR 3.6.1.2.4), secondary containment bypass leakage (SR 3.6.1.3.9), resilient seal primary containment purge valve leakage testing (SR 3.6.1.3.6), or main steam isolation valve leakage (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 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, 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 10 CFR 50, Appendix J, as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

INSERT SR 3.6.1.1.2 and SR 3.6.1.1.3

SR 3.6.1.1.2

The structural integrity of the primary containment is ensured by the successful completion of the Primary Containment Tendon Surveillance Program and by associated visual inspections of the steel liner and penetrations for evidence of deterioration or breach of integrity. This ensures that the structural integrity of the primary containment will be maintained in accordance with the provisions of the Primary Containment Tendon Surveillance Program. Testing and Frequency are consistent with the recommendations of Regulatory Guide 1.35 (Ref. 5).

REFERENCES

1. FSAR, Section 6.2.
2. FSAR, Section 15.6.5.

(continued)

BASES

LCO (continued)

sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into and exit from primary containment.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the primary containment air lock is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door, then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the primary containment boundary is not intact (during access through the OPERABLE door). The ~~utility~~ to open the OPERABLE door, allowance even if it means the primary containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the OPERABLE door is expected to be open. ~~After each entry and exit, the OPERABLE door must be immediately closed.~~

The required administrative controls consist of stationing a dedicated individual to assure closure of the OPERABLE door except during the entry and exit, and to assure the OPERABLE door is relocked after completion of the containment entry and exit.

Note 2 has been included to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.2.2

The seal air flask pressure is verified to be at ≥ [90] psig every 7 days to ensure that the seal system remains viable. It must be checked because it could bleed down during or following access through the air lock, which occurs regularly. The 7 day Frequency has been shown to be acceptable through operating experience and is considered adequate in view of the other indications available to operations personnel that the seal air flask pressure is low.

SR 3.6.1.2.3

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure (Ref. 3), closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is only challenged when the primary containment air lock door is opened, this test is only required to be performed upon entering or exiting a primary containment air lock, but is not required more frequently than once per 184 days. The 184 day Frequency is based on engineering judgment and is considered adequate in view of other administrative controls [such as indications of interlock mechanism status available to operations personnel].

TSTF-17

not normally

used for entry and exit (procedures require strict adherence to single door opening)

TSTF-17

INSERT SR 3.6.1.2.2

given that the interlock is not challenged during the use of the air lock.

TSTF-17

SR 3.6.1.2.4

A seal pneumatic system test to ensure that pressure does not decay at a rate equivalent to > [2] psig for a period of [48] hours from an initial pressure of [90] psig is an effective leakage rate test to verify system performance. The [18] month Frequency is based on the need to perform this Surveillance under the conditions that apply during a

(continued)

TSTF-17

INSERT SR 3.6.1.2.2

every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of primary containment OPERABILITY if the Surveillance were performed with the reactor at power. The 24 month Frequency for the interlock is justified based on generic operating experience. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.1.2 - PRIMARY CONTAINMENT AIR LOCKS

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

2. This bracketed requirement/information has been deleted because it is not applicable to NMPC.

3. Editorial change made for enhanced clarity.

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

5. Typographical/grammatical error corrected.

6. Changes have been made to reflect those changes made to the Specification.

7. These words have been deleted since the primary containment may need to be entered for reasons related to TS that are not specifically on "equipment." This could include sampling and inspections. The intent has not changed in that it must still be related to TS.

8. The change has been made for consistency with similar phrases in other parts of the Bases. B

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary containment isolation within the time limits specified for those PCIVs designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA.

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that the primary containment function assumed in the safety analysis will be maintained. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analysis. One of these barriers may be a closed system.

The [36] and [20] inch primary containment purge valves are PCIVs that are qualified for use during all operational conditions. The [8] and [20] inch primary containment purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure leak tightness. The purge valves must be closed when not being used for pressure control, ALARA, or air quality considerations to ensure that the primary containment boundary assumed in the safety analysis will be maintained.

(which include plugs and caps as listed in Reference 1)

(except for penetrations isolated by excess flow check valves)

the primary containment boundary is maintained

However,

open

may

(inerting, de-inerting)

A two inch bypass line is provided when the primary containment full flow line to the Standby Gas Treatment (SGT) System is isolated.

(since they are fully qualified.)

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The PCIV LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory, and establishing the primary containment boundary during major accidents. As part of the primary containment boundary, PCIV OPERABILITY supports leak tightness of primary containment. Therefore, the safety analysis of any event requiring isolation of primary containment is applicable to this LCO.

The DBAs that result in a release of radioactive material for which the consequences are mitigated by PCIVs are a loss of coolant accident (LOCA), a main steam line break (MSLB), and a fuel handling accident inside primary containment (Refs. 1 and 2). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment purge valves) are minimized. Of the events analyzed in Reference 3, the MSLB is the most limiting event due to radiological consequences. The closure time of the main steam isolation valves (MSIVs) is a significant variable from a radiological standpoint. The MSIVs are required to close within 3 to 5 seconds since the 5 second closure time is assumed in the analysis. The safety analyses assume that the purge valves are closed at event initiation. Likewise, it is assumed that the primary containment is isolated such that release of fission products to the environment is controlled.

The DBA analysis assumes that within 60 seconds after the accident, isolation of the primary containment is complete and leakage terminated, except for the maximum allowable leakage, L_a. The primary containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and PCIV stroke times.

The single failure criterion required to be imposed in the conduct of unit safety analyses was considered in the original design of the primary containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

[The purge valves may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain sealed closed during MODES 1, 2, and 3. In this case, the single failure criterion remains applicable to the primary containment purge valve due to failure in the control circuit associated with each valve. Again, the primary containment purge valve design precludes a single failure from compromising the primary containment boundary as long as the system is operated in accordance with this LCO.]

PCIVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to minimizing the loss of reactor coolant inventory and establishing the primary containment boundary during a DBA.

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. Primary containment purge valves that are not qualified to close under accident conditions must be sealed closed [or blocked to prevent full opening] to be OPERABLE. The valves covered by this LCO are listed with their associated stroke times in the FSAR, Ref. 32.

The normally closed PCIVs are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves and devices are those listed in Reference 20. Purge valves with resilient seals, secondary bypass valves, MSIVs, and hydrostatically tested valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing.

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the primary containment boundary during accidents.

(continued)

BASES

ACTIONS (continued)

subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by Notes 3 and 4. Note 3 ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable PCIV (e.g., an Emergency Core Cooling System subsystem is inoperable due to a failed open test return valve). Note 4 ensures appropriate remedial actions are taken when the primary containment leakage limits are exceeded. Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require the proper actions ~~are~~ be taken. 8

A.1 and A.2

15 rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate.

With one or more penetration flow paths with one PCIV inoperable, except for ~~purge valve or~~ secondary containment bypass leakage not within limits, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The specified time period of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown. 13

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside the primary containment, drywell, and steam tunnel and capable of being mispositioned are in the correct position. The Completion Time for this verification of "once per 31 days for isolation devices outside primary containment, drywell, and steam tunnel," is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For devices inside the primary containment, drywell, or steam tunnel, the specified time period of "prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days," is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and the existence of other administrative controls ensuring that device misalignment is an unlikely possibility.

7

7

if primary containment was de-inerted while in MODE 4,

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides appropriate Required Actions.

15

or more

B

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these devices, once they have been verified to be in the proper position, is low.

two 5 Note 1 TSTF-269

Insert A.1 and A.2

TSTF-269

9

15

B.1

With one or more penetration flow paths with two PCIVs inoperable, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure.

or more 15

B

15

except for secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within limit,

(continued)

The Completion Time of 4 hours for valves other than EFCVs and in penetrations with a closed system is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3.

BASES

ACTIONS

B.1 (continued)

Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

15

except for secondary containment bypass leakage rate, MSIV leakage rate, purge exhaust valve leakage rate, or hydrostatically tested line leakage rate not within limit,

7

or more

C.1 and C.2

When one or more penetration flow paths with one PCIV inoperable, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within ~~4~~ 1 hours. The ~~4~~ 1 hour Completion Time is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. In the event the affected penetration is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. The Completion Time of once per 31 days ~~for verifying that each affected penetration is isolated~~ is appropriate because the ~~valves~~ devices are operated under administrative controls and the probability of their misalignment is low.

72 TSTF-30

15 for penetrations with a closed system

The closed system must meet the requirements of Ref. 6.

TSTF-30

15

10

except for excess flow check valves (EFCVs) and penetrations with a closed system and 72 hours for EFCVs and penetrations with a closed system

The Completion Time of 72 hours for EFCVs is also reasonable considering the mitigating effects of the small pipe diameter and restricting orifice, and the isolation boundary provided by the instrument.

10

12

11

Condition C is modified by a Note indicating this Condition is applicable only to those penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions. This Note is necessary since this Condition is written

or more 7

(continued)

3

This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those devices outside containment and capable of potentially being mispositioned are in the correct position.

BASES

ACTIONS

C.1 and C.2 (continued)

specifically to address those penetrations with a single PCIV.

Required Action C.2 is modified by a Note that applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

D.1

With the secondary containment bypass leakage rate not within limit, the assumptions of the safety analysis are not met. Therefore, the leakage must be restored to within limit within 4 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 4 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration and the relative importance of secondary containment bypass leakage to the overall containment function.

E.1, E.2, and E.3

In the event one or more containment purge valves are not within the purge valve leakage limits, purge valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and

(continued)

TSTF-269 INSERT C.1 and C.2

Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

15 INSERT D.1a

B

Therefore, the leakage rate must be restored to within limit within the Completion Times appropriate for each type of valve leakage: a) hydrostatically tested line leakage not on a closed system and secondary containment bypass leakage are required to be restored within 4 hours; b) MSIV leakage is required to be restored within 8 hours; and c) hydrostatically tested line leakage on a closed system is required to be restored within 72 hours.

B

15 INSERT D.1b

B

The Completion Time of 8 hours for MSIV leakage allows a period of time to restore the MSIV leakage and is acceptable given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown. The 72 hour Completion Time for hydrostatically tested line leakage on a closed system is acceptable based on the available water seal expected to remain as a gaseous fission product boundary during the accident and, in many cases, the associated closed system. The closed system must meet the requirements of Ref. 6.

B

B

TSTF-269

Required Action E.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment once they have been verified to be in the proper position, is low.

BASES

TSTF-30 changes Not shown (11)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1 (continued)

limit offsite doses. Primary containment purge valves that are sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leak tightness. The 31 day Frequency is a result of an NRC initiative, Generic Issue B-24 (Ref. 5), related to primary containment purge valve use during unit operations.

This SR allows a valve that is open under administrative controls to not meet the SR during the time the valve is open. Opening a purge valve under administrative controls is restricted to one valve in a penetration flow path at a given time (refer to discussion for Note 1 of the ACTIONS) in order to effect repairs to that valve. This allows one purge valve to be opened without resulting in a failure of the Surveillance and resultant entry into the ACTIONS for this purge valve, provided the stated restrictions are met. Condition E must be entered during this allowance, and the valve opened only as necessary for effecting repairs. Each purge valve in the penetration flow path may be alternately opened, provided one remains sealed closed, if necessary, to complete repairs on the penetration.

(7)

The SR is modified by a Note stating that primary containment purge valves are only required to be sealed closed in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves may not be capable of closing before the pressure pulse affects systems downstream of the purge valves or the release of radioactive material will exceed limits prior to the closing of the purge valves. At other times when the purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies), pressurization concerns are not present and the purge valves are allowed to be open.

SR 3.6.1.3.2 (1) (7) (12) (h) and 14 inch (4)

(1) This SR verifies that the [24] inch primary containment purge valves are closed as required or, if open, open for an allowable reason. (d) If a purge valve is open in violation of (12)

(13)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.~~2~~ (continued)

~~this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits.~~

~~The SR is also modified by a Note (Note 1) stating that primary containment purge valves are only required to be closed in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves may not be capable of closing before the pressure pulse affects systems downstream of the purge valves, or the release of radioactive material will exceed limits prior to the purge valves closing. At other times when the purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies) pressurization concerns are not present and the purge valves are allowed to be open.~~

The SR is modified by a Note ~~(Note 2)~~ stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA, or air quality considerations for personnel entry, or for Surveillances that require the valves to be open, provided ~~the drywell purge supply and exhaust lines are isolated~~. These primary containment purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other primary containment ~~purge~~ isolation valve requirements discussed in SR 3.6.1.3.~~1~~.

INSERT 3.6.1.3.1-A

SR 3.6.1.3.~~3~~

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment~~, drywell, and steam tunnel,~~ and is required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the primary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those PCIVs outside primary

TSTF-45

and not locked, sealed, or otherwise secured

(continued)

that either: a) the SGT System is OPERABLE (i.e., both subsystems); or b) the primary containment full flow line to the SGT System is isolated and one SGT subsystem is OPERABLE.

TSTF-45

This SR does not apply to valves and blind flanges that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.~~2~~ (continued)

containment, and capable of being mispositioned, are in the correct position. Since verification of ~~valve~~ position for PCIVs outside primary containment is relatively easy, the 31 day Frequency was chosen to provide added assurance that the PCIVs are in the correct positions.

Two Notes are added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in the proper position, is low. A second Note is included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time the PCIVs are open.

These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.~~4~~

TSTF-45

and not locked, sealed, or otherwise secured

This SR verifies that each primary containment manual isolation valve and blind flange located inside primary containment, ~~drywell, or steam tunnel,~~ and required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For PCIVs inside primary containment, ~~drywell, or steam tunnel~~ the Frequency of "prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days," is appropriate since these PCIVs are operated under administrative controls and the probability of their misalignment is low.

if primary containment was de-inerted while in MODE 4

Two Notes are added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since access to these areas is typically restricted during MODES 1, 2, and 3. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in their proper position, is low. A second Note is included to clarify that PCIVs that are open

the primary containment is inerted and

for ALARA and personnel safety

(continued)

BASES

SURVEILLANCE REQUIREMENTS

~~SR 3.6.1.3.6 (continued)~~

~~(e.g., during handling of irradiated fuel), pressurization concerns are not present and the purge valves are not required to meet any specific leakage criteria.~~

7

SR 3.6.1.3.7

Verifying that the full closure isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The full closure isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA analyses. The Frequency of this SR is in accordance with the Inservice Testing Program ~~or 18 months~~. 1 and transient 3

SR 3.6.1.3.8

12

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in ~~SR 3.3.6.1.8~~ LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The ~~18~~ 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 that these components usually pass this Surveillance when performed at the ~~18~~ 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. 1

7 INSERT SR 3.6.1.3.9

INSERT SR 3.6.1.3.10

SR 3.6.1.3.9 11 7

This SR ensures that the leakage rate of secondary containment bypass leakage paths (with the exception of the MSIVs, which are tested per SR 3.6.1.3.12) is less than or equal to the specified leakage rate. This provides assurance that the assumptions in the radiological evaluations ~~of Reference 6~~ that form the basis of the USAR (Ref 2) are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of

1 3 3 3 11 TSTF-30 change not shown

INSERT SR 3.6.1.3.11

(continued)

7 INSERT SR 3.6.1.3.9

SR 3.6.1.3.9

This SR requires a demonstration that each EFCV is OPERABLE by verifying that the valve actuates to the isolation position on an actual or simulated instrument line break condition. This SR provides assurance that the instrumentation line EFCVs will perform as designed. Some hydraulic EFCVs are tested by providing an instrument line break signal with reactor pressure above 600 psig. Testing above this pressure range provides a high degree of assurance that these valves will close during an instrument line break while at normal operating pressure. The remaining hydraulic EFCVs are tested with process fluid or demin water at low pressure. The pneumatic EFCVs are tested by providing an instrument line break signal with pressure at approximately 15 psig to 150 psig. These test pressures are selected to simulate the actual operating conditions the EFCVs are expected to experience during instrument line breaks outside containment.

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 that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

7 INSERT SR 3.6.1.3.10

SR 3.6.1.3.10

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired, and shall be installed in accordance with the manufacturer's recommendations. Other administrative controls, such as those that limit the shelf life and operating life, as applicable, of the explosive charges, must be followed. The Frequency of 24 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.4).

3 INSERT SR 3.6.1.3.11

While the MSIVs are also classified as secondary containment bypass leakage pathway valves, they are evaluated according to SR 3.6.1.3.12, and if not within limits, actions are required to be taken in accordance with ACTION D. 18

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.~~9~~ 11 7 (continued)

the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. This method of quantifying maximum pathway leakage is only to be used for this SR (i.e., Appendix J maximum pathway leakage limits are to be quantified in accordance with Appendix J). The Frequency is required by 10 CFR 50, Appendix J, as modified by approved exemptions (and therefore, the Frequency extensions of SR 3.0.2 may not be applied), since the testing is an Appendix J, Type C test. This SR simply imposes additional acceptance criteria.

1 7 the 7 Testing Program Plan 2

Note 1 is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required.

7

{Bypass leakage is considered part of L_a. ~~(Reviewer's Note: Unless specifically exempted).~~} 1

TSTF-30 changes not shown 3

SR 3.6.1.3.~~10~~ 12 7

3 each 3 1 3 1

The analyses in References ~~2 and 3~~ are based on leakage that is less than the specified leakage rate. Leakage through all four MSIVs must be ≤ (200) scfh when tested at ~~P~~ (31.5) psig). The MSIV leakage rate must be verified to be in accordance with the leakage test requirements of Reference ~~5~~, as modified by approved exemptions. Note 1 is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J (Ref. ~~5~~), as modified by approved

1 (40) 24 7 12 B

the 10CFR50 Appendix J Testing Program Plan. 7

IP MSIV leakage is considered part of L_a. 3

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.10 (continued)

exemptions; thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

SR 3.6.1.3.11

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of References 2 and 3 are met. The combined leakage rates must be demonstrated in accordance with the leakage test frequency of Reference 4, as modified by approved exemptions; thus SR 3.0.2 (which allows Frequency extensions) does not apply.

required by the 10CFR50 Appendix J Testing Program Plan.

[This SR is modified by a Note that states that these valves are only required to meet the combined leakage rate in MODES 1, 2, and 3 since this is when the Reactor Coolant System is pressurized and primary containment is required. In some instances, the valves are required to be capable of automatically closing during MODES other than MODES 1, 2, and 3. However, specific leakage limits are not applicable in these other MODES or conditions.]

SR 3.6.1.3.12

Reviewer's Note: This SR is only required for those plants with purge valves with resilient seals allowed to be open during [MODE 1, 2, or 3] and having blocking devices on the valves that are not permanently installed.

Verifying that each [ ] inch primary containment purge valve is blocked to restrict opening to ≤ [50%] is required to ensure that the valves can close under DBA conditions within the time limits assumed in the analyses of References 2 and 3.

The SR is modified by a Note stating that this SR is only required to be met in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies), pressurization

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.12 (continued)

concerns are not present, thus the purge valves can be fully open. The [18] month Frequency is appropriate because the blocking devices are typically removed only during a refueling outage.

REFERENCES

1. FSAR, Chapter [15].
2. FSAR, Section [6.2].
3. FSAR, [Table 6.2-44].
4. 10 CFR 50, Appendix J.

Section 6.5 15.6.4 Option B

4. USAR, Section 15.2.4.
5. 10 CFR 50.36(c)(2)(ii).

6. USAR, Section 6.2.4.3.2

TSTF-30

TSTF-30 changes Not shown

Technical Requirements Manual.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.1.3 - PRIMARY CONTAINMENT ISOLATION VALVES

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

2. This change was approved to be made in NUREG-1434, Rev. 1 per change package BWR-15, C.9, but apparently was not made. This change was made to the BWR/4 ITS, NUREG-1433, Rev. 1.

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

4. Typographical/grammatical error corrected.

5. This paragraph in the Applicable Safety Analyses Section of Bases 3.6.1.3 has been modified since it is incorrect; neither the DBA analysis nor the IST Program have a specific assumption for closure time of PCIVs. The analysis assumes the valves will close prior to fuel damage, which is not expected for some time. The closure times are currently specified in the USAR, and are based upon such factors as valve size and valve operator capability. In addition, the words in SR 3.6.1.3.5 stating that the isolation times are in the IST Program have also been deleted since these times are also located in the USAR.

6. This bracketed requirement/information has been deleted because it is not applicable to NMP2.

7. Changes have been made to reflect those changes made to the Specification.

8. This change was approved to be made in NUREG-1434, Rev. 1 per change package BWR-16, C.23, Rev. 1, but apparently was not made. This change was made to the BWR/4 ITS, NUREG-1433, Rev. 1.

9. This change was approved to be made in NUREG-1434, Rev. 1 per change package BWR-15, C.5, but apparently was not made. A similar change was made to NUREG-1434, Rev. 1, Bases 3.6.4.2, Required Actions A.1 and A.2.

10. The NMP2 design includes EFCVs and TIPs, similar to the BWR/4 design. Therefore, the Bases for Required Action C.1 and C.2 has been modified and proposed Bases for SR 3.6.1.3.4, SR 3.6.1.3.9, and SR 3.6.1.3.10 have been added, consistent with the BWR/4 ITS (NUREG-1433, Rev. 1).

11. Some of the Bases changes for TSTF-30, Rev. 2 have not been adopted since the SRs/information is not applicable to NMP2. 1 (B)

12. These changes have been made for consistency with similar phrases in other parts of the Bases and/or to be consistent with the Specification.

13. This change was approved to be made in NUREG-1434, Rev. 1 per change package BWR-15, C.4, but apparently was not made. This change was made to the BWR/4 ITS, NUREG-1433, Rev. 1.

14. Editorial change made for enhanced clarity.

15. Changes have been made to be consistent with the Specification. These changes are also consistent with proposed TSTF-207, Rev. 3 and proposed TSTF-30, Rev. 3, except where plant specific differences apply or where typographical/consistency errors are noted. B

16. The discussion in the LCO section about closed valves is modified. This editorial preference is based on an incomplete and misleading discussion of the valves. This change does not modify the requirements or the interpretation of the requirements. B

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 ~~Primary Containment~~ Pressure

Drywell and Suppression chamber

BASES

BACKGROUND

The ~~primary containment~~ pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).

drywell and suppression chamber internal

~~The limits on primary containment [to secondary containment differential] pressure have been developed based on operating experience. The auxiliary building, which is part of the secondary containment, completely surrounds the lower portion of the primary containment. Therefore, the primary containment design external differential pressure, and consequently the Specification limit, are established relative to the auxiliary building pressure. The auxiliary building pressure is kept slightly negative relative to the atmospheric pressure to prevent leakage to the atmosphere.~~

drywell

minimum

Transient events, which include inadvertent ~~containment~~ spray initiation, can reduce the ~~primary containment~~ pressure (Ref. 1). Without an appropriate limit on the ~~negative containment~~ pressure, the design limit for negative ~~internal~~ pressure of ~~[-3.0]~~ psid could be exceeded. ~~Therefore, the Specification pressure limits of [-0.1 and -1.0 psid] were established (Ref. 2).~~

drywell and suppression chamber internal

containment differential

The limitation on the ~~primary [to secondary containment differential]~~ pressure provides added assurance that the peak LOCA ~~primary containment~~ pressure does not exceed the design value of ~~15~~ psig (Ref. 1).

maximum drywell and suppression chamber internal

drywell and suppression chamber

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for the entire spectrum of break sizes for postulated LOCAs inside containment (Ref. ~~3~~). Among the inputs to the design basis analysis is the initial ~~primary containment~~ internal pressure. ~~The primary containment [to secondary containment differential] pressure can affect the initial containment internal pressure.~~ The initial pressure limitation requirements ensure that peak primary containment pressure for a DBA LOCA does not exceed the design value of ~~15~~ psig and that peak negative pressure for an inadvertent

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.1.4 - DRYWELL AND SUPPRESSION CHAMBER PRESSURE

1. Changes have been made to reflect the changes made to the Specification.

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

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

4. This statement is duplicative of the first paragraph in the Applicable Safety Analysis (ASA) section and first paragraph of the LCO section. Since this type of information is more appropriate for the ASA and LCO sections, it has been deleted from the Background section. B

INSERT ASA

In addition, the drywell average air temperature is the limiting initial condition used to determine the maximum negative differential pressure across the primary containment boundary following an inadvertent drywell spray actuation (Ref. 1).

INSERT LCO

and the design negative differential pressure across the primary containment boundary is not exceeded.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.1.7 - SUPPRESSION CHAMBER-TO-DRYWELL VACUUM BREAKERS

1. A new Bases has been added, ITS Bases 3.6.1.7. This Bases is from BWR/4 ISTS 3.6.1.8 (NUREG-1433), since the NMP2 design is similar to the BWR/4 design with regard to the vacuum breakers. Therefore, the BWR/4 Bases are used and any deviations from the BWR/4 ISTS are discussed below.

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

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

4. The statement has been modified since it is incorrect; the pressure could be positive or negative depending upon the situation. Also, the design basis only assumes the pressure is within the limits, not positive. Therefore, the vacuum breakers are required to remain closed only "until" the suppression pool is at a positive pressure relative to the drywell. At this time, they may be open to perform their design function (i.e., relieve pressure).

5. Changes have been made to reflect those changes made to the Specification.

6. Inadvertent actuation of a spray system is not the main concern for depressurizing the drywell, a LOCA inside the drywell is the main concern. Therefore, this section has been reworded to place proper emphasis on the proper reason. In addition, inadvertent actuation of suppression pool spray is not a concern at all relative to causing an excessive negative pressure event; drywell spray is the system that can cause this event. Therefore the Bases have been changed from suppression pool spray to drywell spray when discussing this event. 1B B

7. Editorial change made for enhanced clarity.

8. These changes have been made for consistency with similar phrases in other parts of the Bases and/or to be consistent with the Specification.

1 INSERT B 3.6.2.1 BACKGROUND

The suppression pool must quench all the steam released through the downcomer lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment that ensures that the peak containment pressure is maintained below the design value (45 psig). Suppression pool average temperature (along with LCO 3.6.2.2, "Suppression Pool Water Level") is a key indication of the capacity of the suppression pool to fulfill these requirements. 1B

BASES

LCO (continued)

selected to provide margin below the {110}°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ ~~{95}~~ 90°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > ~~{95}~~ 90°F is short enough not to cause a significant increase in plant risk.

TSTF-206

c. Average temperature ≤ {110}°F when all OPERABLE IRM channels are ≤ [25/40] divisions of full scale on Range 7. This requirement ensures that the plant will be shut down at > {110}°F. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

with THERMAL POWER ≤ 1% RTP

all changes TSTF-206

~~[Note that [25/40] divisions of full scale on IRM Range 7 is a convenient measure of when the reactor is producing power essentially equivalent to 1% RTP.] At this power level, heat input is approximately equal to normal system heat losses.~~

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. 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 suppression pool average temperature within limits is not required in MODE 4 or 5.

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power ~~indication~~ limit, the initial conditions exceed the conditions assumed for the Reference 1 and ~~d~~ analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above that assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool temperature to be restored to below the limit. Additionally, when pool temperature is > ~~{95}~~ 90°F,

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

rates (provided pool temperature remains ≤ {120}°F). Additionally, when pool temperature is > {110}°F, increased monitoring of pool temperature is required to ensure that it remains ≤ {120}°F. The once per 30 minute Completion Time is adequate, based on operating experience. Given the high pool temperature in this condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

E.1 and E.2

If suppression pool average temperature cannot be maintained ≤ {120}°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < {200} psig within 12 hours and the plant must be brought to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

Continued addition of heat to the suppression pool with pool temperature > {120}°F could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure. Furthermore, if a blowdown were to occur when temperature was > {120}°F, the maximum allowable bulk and local temperatures could be exceeded very quickly.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. Average temperature is determined by taking an arithmetic average of ~~the~~ at least one OPERABLE ~~suppression pool water temperature channels~~ post accident monitoring instrumentation channel in each suppression pool quadrant. Alternately, average temperature can be determined by taking an arithmetic average of 10 OPERABLE suppression pool water temperature channels, which are distributed in different suppression pool sectors. There is no divisional requirement with respect to the instrument channels for this SR. The 24 hour Frequency has been shown to be acceptable based on operating experience. When heat is being added to the suppression pool by testing, however, it

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.2.1 - SUPPRESSION POOL AVERAGE TEMPERATURE

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

2. The discussions of the four different concerns that lead to the development of the suppression pool average temperature limits have been deleted. The appropriate analysis is described in the USAR (References 1 and 2) and discussion in the Bases is not needed for understanding this Specification.

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

4. Changes have been made to reflect those changes made to the Specification.

5. Typographical error corrected.

6. Editorial change made for enhanced clarity.

7. This sentence has been deleted since it is not relevant to the LCO discussion. It is simply stating that 1% RTP is approximately equal to normal system heat losses. It does not provide any detail as to why this is acceptable. This information is more appropriate for the Applicable Safety Analyses section, which is the section that normally provides this type of information. The Applicable Safety Analyses section describes that initial pool temperature is an assumption of the analyses of References 1 and 2, and that Reference 3 requires certain suppression pool temperature analyses. This provides adequate detail and references to the suppression pool analyses. B

BASES

ACTIONS

A.1 (continued)

cooling capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

Insert Action B.1

B.1 and B.2

any associated TSTF-230

If the Required Action and Required Completion Time of Condition A cannot be met or if two RHR suppression pool cooling subsystems are 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 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.

TSTF-230

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists 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 being locked, sealed, or secured. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable, since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.2.3 - RHR SUPPRESSION POOL COOLING

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

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

3. The specific requirement for the subsystems to be powered from two safety related independent power supplies has been deleted since the design of the system already reflects this. There are only two subsystems, and each is powered from a separate power supply; the power supplies cannot be cross-connected. This statement is not used in other LCO Bases where the system is designed with independent power supplies (e.g., Bases 3.6.1.6, "RHR Drywell Spray," and Bases 3.6.3.1, "Primary Containment Hydrogen Recombiners"). The BWR/4 Bases has this statement since some BWR/4s have two pumps per subsystem, with only one required for the subsystem to be Operable (as described in the BWR/4 Bases), and due to the electrical design of the system, one pump in each subsystem is powered from the same electrical division. Thus, for this design, the words in the NUREG are necessary. However, as described above, NMP2 does not have this design.

4. Editorial change made for enhanced clarity.

5. Changes have been made to reflect those changes made to the Specification.

6. Typographical/grammatical error corrected.

7. The IST Program at NMP2 is not required to provide information for trend purposes. Therefore, these words have been deleted.

8. A new Bases has been added, ITS Bases 3.6.2:4. This Bases is from the BWR/4 ISTS (NUREG-1433 ISTS B 3.6.2.4), since the NMP2 design is similar to the BWR/4 design with regard to RHR suppression pool spray. Therefore, the BWR/4 Bases is used and any deviations from the BWR/4 ITS Bases are discussed in the Justification for Deviations for ITS Bases: 3.6.2.4.

9. These changes have been made for consistency with similar phrases in other parts of the Bases. B

BASES

ACTIONS

A.1 (continued)

limit, the low probability of the failure of the OPERABLE recombiner, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limit.

B.1 and B.2

~~Reviewer's Note: This Condition is only allowed for units with an alternate hydrogen control system acceptable to the technical staff.~~

With two primary containment hydrogen recombiners inoperable, the ability to perform the hydrogen and oxygen control function via an alternate capability is must be verified by administrative means within 1 hour. The alternate hydrogen control capability is are provided by the Primary Containment Vent, Purge, and Nitrogen System and one RHR drywell spray subsystem. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. ~~[Reviewer's Note: The following is to be used if a non-Technical Specification alternate hydrogen control function is used to justify this Condition.]~~ In addition, the alternate hydrogen and oxygen control system capability must be verified once per 12 hours thereafter to ensure its continued availability. ~~{Both}~~ the ~~{initial}~~ verification ~~{and all subsequent verifications}~~ may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen and oxygen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen and oxygen control system. If the ability to perform the hydrogen and oxygen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen and oxygen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen and oxygen in the amounts capable of exceeding the flammability limit.

(continued)

1 * INSERT BWR/4 ISTS B 3.6.3.3

1

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.~~2~~ 3 Primary Containment Oxygen Concentration

BASES

The primary containment is 2

BACKGROUND

~~All nuclear reactors must be~~ designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen < 4.0 v/o works together with the Hydrogen Recombiner System (LCO 3.6.3.1, "Primary Containment Hydrogen Recombiners") and the ~~Drywell Cooling System Fans~~ RHR Drywell Spray System 5 4 (LCO ~~3.5.3.2~~ 3.6.1.6, "~~Drywell Cooling System Fans~~") to provide redundant and diverse methods to mitigate events that produce hydrogen and oxygen. For example, an event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain ~~< 4.0~~ ≤ 5.0 4 v/o and no combustion can occur. Long term generation of both hydrogen and oxygen from radiolytic decomposition of water may eventually result in a combustible mixture in primary containment, except that the hydrogen recombiners remove hydrogen and oxygen gases faster than they can be produced from radiolysis and again no combustion can occur. This LCO ensures that oxygen concentration does not exceed 4.0 v/o during operation in the applicable conditions.

5 RHR Drywell Spray

B

APPLICABLE SAFETY ANALYSES

The Reference 1 calculations assume that the primary containment is inerted when a Design Basis Accident loss of coolant accident occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of metal water reaction in the reactor core will not produce combustible gas mixtures in the primary containment. Oxygen, which is subsequently generated by radiolytic decomposition of water, is recombined by the hydrogen recombiners (LCO 3.6.3.1) more rapidly than it is produced.

Primary containment oxygen concentration satisfies Criterion 2 of ~~the NRC Policy Statement~~ Reference 2 4

(continued)

* THIS BWR/4 BASES INSERT WAS USED TO MATCH THE BWR/4 SPECIFICATION INSERTED IN THE LCO SECTION

Insert Page B 3.6-80a

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.3.2 - PRIMARY CONTAINMENT OXYGEN CONCENTRATION

1. A new Bases has been added, ITS Bases 3.6.3.2. This Bases is from the BWR/4 ISTS (NUREG-1433 ISTS B 3.6.3.3), since the NMP2 design is similar to the BWR/4 design with regard to the inerting requirements of the primary containment. Therefore, the BWR/4 Bases are used and any deviations from the BWR/4 ISTS are discussed below.

2. Editorial change made for enhanced clarity.

3. Not used. 1 B

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

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

6. Typographical/grammatical error corrected.

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. 3

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.

SR 3.6.4.1.2 and SR 3.6.4.1.3

TSTF-18 In each access opening one

Verifying that {secondary containment} equipment hatches and access doors are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the {secondary containment} will not occur. In this application, the term "sealed" has no connotation of leak tightness. Maintaining {secondary containment} OPERABILITY requires verifying each door in the access opening is closed, except when the access opening is being used for entry and exit; then, at least one door must remain closed. The 31 day Frequency for these SRs has been shown to be adequate based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator.

Insert SR3.6.4.1.3 TSTF-18 1 6

(continued)

TSTF-18 INSERT SR 3.6.4.1.3

An access opening contains one inner and one outer door. In some cases, [secondary] containment access openings are shared such that a [secondary] containment barrier may have multiple inner or multiple outer doors. The intent is not to breach the [secondary] containment at any time when [secondary] containment is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times. However, all [secondary] containment access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being performed on an access opening.

For these cases, the access openings share the inner door or the outer door, i.e., the access openings have a common inner door or outer door.

; i.e., all inner doors closed or all outer doors closed. Thus, each access opening has one door closed.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.4.1 - SECONDARY CONTAINMENT

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

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

3. These changes have been made for consistency with similar phrases in other parts of the Bases and/or to be consistent with the Specification.

4. Changes have been made to reflect those changes made to the Specification.

5. ISTS SRs 3.6.4.1.4 and 3.6.4.1.5 are tests that ensure the Secondary Containment is OPERABLE; the leak tightness of the Secondary Containment boundary is within the assumptions of the accident analyses. However, they are written in such a manner that they imply that if a SGT subsystem is inoperable, the SRs are failed ("Verify each standby gas treatment (SGT) subsystem will/can..."). As stated above, this is not the intent of the SRs. Therefore, to ensure this misinterpretation cannot occur, the SRs and this Bases description have been rephrased to more clearly convey the original intent of the SRs, to verify the Secondary Containment is OPERABLE. With the new wording, if a SGT subsystem is inoperable, SRs 3.6.4.1.4 and 3.6.4.1.5 will still be met and only the SGT System Specification, LCO 3.6.4.3, will be required to be entered. This is clearly identified in the Bases.

6. The Bases have been modified to provide additional clarity when describing the design of an access opening. B

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, that are released during certain operations when primary containment is not required to be OPERABLE, or that take place outside primary containment, are maintained within the secondary containment boundary.

The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), and blind flanges are considered passive devices. ~~Check valves or other automatic valves designed to close without operator action following an accident are considered active devices. Isolation barrier(s) for the penetration are discussed in Reference 2.~~

Automatic SCIVs (i.e. dampers) close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or other accidents.

Other penetrations are isolated by the use of valves in the closed position or blind flanges (which includes plugs and caps as listed in Reference 3).

APPLICABLE SAFETY ANALYSES

The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accidents for which the secondary containment boundary is required are a loss of coolant accident (Ref. 1) and a fuel handling accident inside

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

primary containment (Ref. 6), and a fuel handling accident in the auxiliary building (Ref. 4). The secondary containment performs no active function in response to each of these limiting events, but the boundary established by SCIVs is required to ensure that leakage from the primary containment is processed by the Standby Gas Treatment (SGT) System before being released to the environment.

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The automatic power operated isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 6.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed or open in accordance with appropriate administrative controls, automatic SCIVs are de-activated and secured in their closed position, and blind flanges are in place. These passive isolation valves or devices are listed in Reference 6.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other

(continued)

BASES

APPLICABILITY (continued)

situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies. ~~Moving irradiated fuel assemblies in the [primary or secondary containment] may also occur in MODES 1, 2, and 3.~~

In the secondary containment

4

1 B

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when the need for ~~[secondary containment]~~ isolation is indicated.

2

3

The second Note provides clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path(s) must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criteria are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

secondary containment. This Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

4

The Completion Time of once per 31 days is appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low.

Required Action A.2 is modified by a Note that applies to devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

4 isolation B

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the low probability of a DBA, which requires the SCIVs to close, occurring during this short time.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies each secondary containment isolation manual valve and blind flange that is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the {secondary containment} boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those SCIVs in {secondary containment} that are capable of being mispositioned are in the correct position.

Since these SCIVs are readily accessible to personnel during normal unit operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide added assurance that the SCIVs are in the correct positions.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these SCIVs, once they have been verified to be in the proper position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open.

INSERT SR 3.6.4.2.1

SR 3.6.4.2.2

Verifying the isolation time of each power operated and each automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR {are in accordance with the Inservice Testing Program or 92 days}.

TSTF-46

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a {secondary containment} isolation signal is required to prevent leakage of radioactive material from {secondary containment} following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a {secondary containment} isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in ~~SR 3.3.6.2.5~~ overlaps this SR to provide complete testing of the safety function. The ~~[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 {[18] month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation,"

While this Surveillance can be

which is based on the refueling cycle

REFERENCES

1. FSAR, Section {15.6.5}.
2. ~~FSAR, Section {6.2.3}.~~
3. ~~FSAR, Section {15.7.6}.~~
4. FSAR, Section {15.7.4}.
5. ~~FSAR, Section [/].~~
6. 10 CFR 50.36 (c)(2)(ii).

Technical Requirements Manual.

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS BASES: 3.6.4.2 - SECONDARY CONTAINMENT ISOLATION VALVES (SCIVs)

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

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

3. Typographical/grammatical error corrected.

4. These changes have been made for consistency with similar phrases in other parts of the Bases and/or to be consistent with the Specification.

5. Editorial change made for enhanced clarity.

6. The words in SR 3.6.4.2.2, stating that the isolation times are in the IST Program have been deleted. The IST Program does not include the times for the SCIVs. They are located in the Technical Requirements Manual.

7. The discussion in the LCO section about closed valves is modified. This editorial preference is based on an incomplete and misleading discussion of the valves. This change does not modify the requirements or the interpretation of the requirements. B

BASES

ACTIONS

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

suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

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,

Required Action E.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving 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 sufficient reason to require a reactor shutdown.

Insert E.1, E.2, and E.3

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

(from the control room using the manual initiation switch)

Operating each SGT subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

SR 3.6.4.3.2

This SR verifies that the required SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specified test frequencies

(continued)

L.3 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   This change extends the Frequency for performing a visual inspection of the suppression chamber to a Frequency already approved in another Surveillance and 10 CFR 50 Appendix J. This Frequency has been determined to be adequate since no failures have been detected in this Surveillance. Therefore, this change does not significantly increase the probability of a previously analyzed accident. An increase in the Surveillance interval will not affect the capability of the suppression chamber to perform its function nor alter the assumptions relative to the mitigation of an accident. Therefore, this change does not significantly increase the consequences of a previously analyzed accident.

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

   This change does not introduce a new mode of plant operation and does not involve a physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change does not involve a significant reduction in a margin of safety since experience has shown that the suppression chamber passes the Surveillance when performed at the proposed Frequency.

L.4 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   This change deletes the requirement associated with CTS 4.6.2.1.e.1 to obtain an NRC review of the test schedule for subsequent tests if any leak rate test result is not within the required limits. The subsequent test schedule has already been approved by the NRC in the Technical Specifications. If two consecutive tests fail, then the test must be performed at every refueling outage until two consecutive tests pass. The requirement to obtain NRC concurrence with the test schedule is not assumed to be an initiator of any analyzed event and does not impact assumptions of any design basis accident. Additionally, the concurrence is not required or assumed for the mitigation of any accident. Therefore, this proposed change does not involve an increase in the probability or consequences of an accident previously evaluated.

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

   This change does not introduce a new mode of plant operation and does not involve a physical modification to the plant. This change deletes a requirement to obtain NRC concurrence for a leak rate test schedule that is already approved by the NRC. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change does not involve a significant reduction in a margin of safety since the increased test schedule is already approved by the NRC and since experience has shown that the Surveillance normally meets its acceptance criterion when performed at the normal Frequency.

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   This change relaxes the allowed restoration times to isolate the affected penetration(s) if one valve is inoperable from 4 hours to 8 hours for MSIVs and from 4 hours to 72 hours for PCIVs in penetrations with a closed system and only one PCIV. The proposed change does not increase the probability of an accident. The time allowed to isolate the penetration by use of de-activated automatic valve, blind flange, etc. is not assumed to be an initiator of any analyzed event. The MSIVs and other PCIVs isolate to control leakage from the primary containment during accidents. Allowing the additional time to isolate the MSIVs and other PCIVs will not significantly increase the consequences of an accident. The consequences will be the same for the proposed times as for the current times. The additional times, however, will allow more time to repair the inoperable MSIV or other PCIV and possibly avoid a shutdown. Shutting down the plant is a transient which puts thermal stress on components which could increase the chances of challenging safety systems. In addition, the closed system piping or water seal will ensure primary containment integrity is maintained. This change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated. 1 B

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

   This change will not result in any changes to equipment design or capabilities or the operation of the plant. The proposed change will still require the MSIVs and other PCIVs to be restored to OPERABLE status. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change relaxes the allowed restoration time for isolating the affected penetration(s) if one valve is inoperable from 4 hours to 8 hours for MSIVs and from 4 hours to 72 hours for PCIVs in penetrations with a closed system and only one PCIV. The margin of safety is not significantly reduced because, for MSIV penetrations, another MSIV in the penetration flow path remains Operable and 1 B

L.1 CHANGE

3. (continued)

capable of isolating the penetrations, and for the other PCIVs, the closed system piping or the water seal acts as a primary containment isolation barrier. Also, the time allowed to isolate penetrations is not assumed in any safety analysis and current safety analysis assumptions will be maintained. The added time also allows more time to isolate the MSIV and other PCIVs.

Isolating the MSIV penetrations will require a reduction in power and has the potential for tripping the plant. A reduction in power or a plant trip is considered a transient due to the thermal effects it has on plant equipment. During the additional time allowed, a limiting event would still be assumed to be within the bounds of the safety analysis, assuming no single active failure. Therefore, this change does not involve a significant reduction in a margin of safety.

L.12 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   This change relaxes the allowed restoration times to restore leakage of hydrostatically tested valves and secondary containment bypass leakage pathway valves. The extension is from the current 1 hour to 4 hours for valves in hydrostatically tested lines not on a closed system and for secondary containment bypass leakage paths, 8 hours for MSIVs, and 72 hours for valves in hydrostatically tested lines on a closed system. The PCIV leakage is not assumed to be an initiator of any analyzed event. Therefore, this change will not involve in an increase in the probability of an accident previously evaluated. Allowing additional time to restore leakage will not significantly increase the consequences of an accident. The consequences will be the same for the proposed times as for the current times. The additional times, however, will allow more time to repair the inoperable valves and possibly avoid a shutdown. Shutting down the plant is a transient which puts thermal stress on components which could increase the chances of challenging safety systems. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

   This change will not result in any changes to equipment design or capabilities or the operation of the plant. The proposed change will still require the leakage values to be restored to within limits. Therefore, this change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change relaxes the allowed restoration time for restoring the leakage to within limits. The margin of safety is not significantly reduced because another Operable valve remains to isolate the flow path, the system is a closed system, or the line is hydrostatically sealed. The additional times, however, will allow more time to repair the inoperable valves and possibly avoid a shutdown. Shutting down the plant is a transient which puts thermal stress on components which could increase the chances of challenging safety systems. Therefore, this change does not involve a significant reduction in a margin of safety.

L.4 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   This change provides an exception allowing the vacuum breakers to be open when performing required Surveillances (the exception is to the Surveillance that would otherwise require the vacuum breakers to be closed at all times). The vacuum breakers are not assumed to be an initiator of any previously analyzed accident. Therefore, this change does not involve a significant increase in the probability of an accident previously evaluated. The surveillance exception is made only for circumstances where the vacuum breaker is under the immediate control of an operator (manually opening to confirm operability). As such, the vacuum breaker is expected to continue to perform its intended and assumed safety function, and therefore this change does not involve a significant increase in the consequences of an accident previously evaluated.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   The change will not result in a significant reduction in a margin of safety because the vacuum breakers are still required to be Operable. The exception is made only for circumstances where the vacuum breaker is under the immediate control of an operator (manually opening to confirm operability). As such, the vacuum breaker is expected to continue to perform its intended and assumed safety function, and therefore this change does not involve a significant reduction in the margin of safety.

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ACTIONS

G.1 and G.2 (continued)

within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions are modified by a Note indicating that the applicable Conditions of LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," be entered and the Required Actions taken if the inoperable SW System or UHS results in an inoperable RHR shutdown cooling subsystem. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for the RHR Shutdown Cooling System.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

Verification that the water temperature of the intake tunnels is ≥ 38°F ensures that frazil ice, which can block the intake tunnels, cannot form. This ensures that the intake tunnels can perform their intended function. This Surveillance is only required to be met when SR 3.7.1.5 and SR 3.7.1.8 are not satisfied. With the Intake Deicer Heater System OPERABLE (and SR 3.7.1.5 and SR 3.7.1.8 met), frazil ice cannot form even with the intake tunnels water temperature < 38°F. The 12 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.2

This SR verifies the water level in the SW pump intake bay to be sufficient for the proper operation of the SW pumps (net positive suction head and pump vortexing are considered in determining this limit). The water level limit, 233.1 ft, is referenced to mean sea level. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES. B

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.3

Verification of each SW subsystem supply header temperature ensures that the heat removal capability of the SW System is within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES. However, if a SW subsystem supply header water temperature is ≥ 75°F, the Surveillance must be performed more frequently (every 4 hours if ≥ 75°F and every 2 hours if ≥ 79°F), since the condition is closer to the maximum water temperature limit.

SR 3.7.1.4

Verification that each required SW pump is in operation ensures that an adequate number of SW pumps are operating to perform the long term containment cooling function during a LOCA. The 24 hour Frequency is based on operating experience and the operator's inherent knowledge of plant status, including changes in SW pump operating status.

SR 3.7.1.5

The current for each required heater feeder cable is required to be checked to ensure the proper number of heaters are OPERABLE for each intake deicer heater division. The Surveillance is performed by verifying, at the motor control centers, that the current is ≥ 20 amps (total for all three phases when adjusted to degraded voltage conditions, i.e., 518 volts) in each intake structure for each division. The current limit is based upon ensuring 14 heaters are OPERABLE (which includes in operation) in an intake structure. This Surveillance is only required to be met when SR 3.7.1.1 is not satisfied, since with the intake tunnels water temperature ≥ 38°F (i.e., SR 3.7.1.1 met), frazil ice cannot form even with the intake deicer heaters inoperable. The 7 day Frequency is based on operating experience that has shown that these components usually pass this Surveillance when performed at this Frequency.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.6

Verifying the correct alignment for each manual, power operated, and automatic valve in each SW subsystem flow path provides assurance that the proper flow paths will exist for SW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

This SR is modified by a Note indicating that isolation of the associated SW subsystem to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the SW subsystem. As such, when all SW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the SW subsystem is still OPERABLE.

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

SR 3.7.1.7

This SR verifies that the automatic isolation valves (i.e., SW isolation valves servicing non-safety related equipment, SW supply header cross connect valves, and SW pump discharge valves of non-operating SW pumps) of the SW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during a transient event (i.e., LOOP). This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the SW pump (and associated pump discharge valve opening capability) in each subsystem.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.7 (continued)

Operating experience has shown that these components usually pass the SR when performed on the 24 month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

SR 3.7.1.8

The resistance of each required heater feeder cable and associated heater elements is required to be checked to ensure the required heaters are OPERABLE for each intake deicer heater division. The Surveillance is performed by verifying that the resistance is ≥ 28 ohms for each required heater feeder cable and associated heater element. The minimum resistance is based on ensuring the intake structure bar racks are heated sufficiently such that the SW flow assumed to safely shutdown the unit can be achieved through the intake structures. This Surveillance is only required to be met when SR 3.7.1.1 is not satisfied, since with the intake tunnels water temperature ≥ 38°F (i.e., SR 3.7.1.1 met), frazil ice cannot form even with the intake deicer heaters inoperable. The 24 month Frequency is based on operating experience that has shown that these components usually pass this Surveillance when performed at this Frequency.

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.
2. USAR, Section 9.2.1.
3. USAR, Section 9.2.5.
4. USAR, Tables 9.2-1 and 9.2-1A.
5. USAR, Section 6.2.
6. USAR, Section 6.3.
7. USAR, Chapter 15.
8. USAR, Appendix A.
9. USAR, Section 6.2.2.
10. 10 CFR 50.36(c)(2)(ii).

B 3.7 PLANT SYSTEMS

B 3.7.2 Control Room Envelope Filtration (CREF) System

BASES

BACKGROUND

The CREF System provides a radiologically controlled environment from which the unit can be safely operated following a Design Basis Accident (DBA). The control room envelope consists of all rooms and areas located in the main control room and relay room of the control building. Included in the envelope are the main control room, relay room, instrument shop, training room, shift supervisor's office, lunch room, toilets, corridors, work release room, and HVAC equipment rooms (Ref. 1).

The safety related function of the CREF System used to control radiation exposure consists of two independent and redundant high efficiency air filtration subsystems for treatment of recirculated air and outside supply air. Each subsystem includes a control room outdoor air special filter train (CROASFT), which consists of an electric heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a second HEPA filter, a filter booster fan, and the associated ductwork and dampers. The electric heater is used to limit the relative humidity of the air entering the filter train. Prefilters and HEPA filters remove particulate matter that may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay. Each subsystem also includes the necessary outside air intake(s) and two air conditioning units (fan portion only), one for the control room and one for the relay room. Each outside air intake is capable of providing 100% of the necessary makeup flow. Therefore, normally only one outside air intake is necessary. However, when the unit is in MODE 1, 2, or 3 with MSIV leakage > 15 scfh for any MSIV, both outside air intakes, including the capability to isolate the intakes, are necessary. Both outside air intakes are required in these conditions since the accident analysis assumes the most contaminated outside air intake is isolated 8 hours after the accident to ensure the dose to control room envelope personnel does not exceed the limit. The outside air intake that is not isolated continues to be capable of providing 100% of the necessary makeup flow. The two required outside air intakes are allowed to be common to both subsystems (since there are only two outside air intakes for the CREF System). Alternately, if MSIV leakage

(continued)

BASES

BACKGROUND (continued)

is > 15 scfh for any MSIV, an additional analysis may be performed to determine the "effective" MSIV leakage. The "effective" MSIV leakage is the individual MSIV leak rate when all four main steam lines are assumed to leak at the same rate, and the doses in the control room envelope are equivalent to those when the individual "as-left" valve leak rates are used. If the "effective" MSIV leakage is ≤ 15 scfh, then only one outside air intake is necessary. B

The CROASFT portion of the safety related CREF System is normally in standby, but the remaining portions of the CREF System (the outside air intakes and fan portion of the air conditioning units) are operated to maintain the control room envelope environment during normal operation. Upon receipt of the initiation signal(s) (indicative of conditions that could result in radiation exposure to control room envelope personnel), the CREF System automatically switches to the emergency pressurization mode of operation to prevent infiltration of contaminated air into the control room envelope. A system of valves and dampers redirects all control room envelope outside air flow through the two CROASFTs. In addition, a portion of the control room air is recirculated through the CROASFTs. The air conditioning units (fan portion only) maintain the 1/8 inch positive pressure; the CROASFT booster fan only provides the motive force to overcome the added resistance of the CROASFT being in service. B B

The CREF System is designed to maintain the control room envelope environment for a 30 day continuous occupancy (i.e., considering the occupancy factors of NUREG-0800, Table 6.4-1, Ref. 2) after a DBA, while limiting the dosage to personnel to not more than 5 rem whole body or its equivalent to any part of the body. CREF System operation in maintaining the control room envelope habitability is discussed in the USAR, Sections 6.4.1 and 9.4.1 (Refs. 3 and 4, respectively). B B

APPLICABLE SAFETY ANALYSES

The ability of the CREF System to maintain the habitability of the control room envelope is an explicit assumption for the safety analyses presented in the USAR, Chapters 6 and 15 (Refs. 5 and 6, respectively). The emergency pressurization mode of the CREF System is assumed to operate following a loss of coolant accident, main steam line break, fuel handling accident, and control rod drop accident. The radiological doses to control room envelope personnel as a result of the various DBAs are summarized in Reference 6. B B

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

No single active failure will cause the loss of outside or recirculated air from the control room envelope.

The CREF System satisfies Criterion 3 of Reference 7. B

LCO

Two redundant subsystems of the CREF System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in exceeding a dose of 5 rem to the control room operators in the event of a DBA.

The CREF System is considered OPERABLE when the individual components necessary to control operator exposure are OPERABLE in both subsystems. A subsystem is considered OPERABLE when its associated:

a. CROASFT is OPERABLE;

b. Air conditioning units (fan portion only) are OPERABLE (one for the control room and one for the relay room), including the ductwork, to maintain air circulation to and from the control room envelope; and B

c. Necessary outside air intake(s) are OPERABLE. When the unit is not in MODES 1, 2, and 3, or when the unit is in MODE 1, 2, or 3 with MSIV leakage $\leq$ 15 scfh for each MSIV, only one outside air intake is necessary. When the unit is in MODE 1, 2, or 3 with MSIV leakage > 15 scfh for any MSIV, both outside air intakes, including the capability to isolate the intakes, are necessary and are allowed to be common to both subsystems. Alternately, if MSIV leakage is > 15 scfh for any MSIV, an additional analysis may be performed to determine the "effective" MSIV leakage. If the "effective" MSIV leakage is $\leq$ 15 scfh, then only one outside air intake is necessary.

A CROASFT is considered OPERABLE when its associated filter booster fan is OPERABLE; HEPA filter and charcoal adsorber are not excessively restricting flow and are capable of performing their filtration functions; and heater, ductwork, valves, and dampers are OPERABLE, and air circulation through the filter train can be maintained.

In addition, the control room envelope boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors, such that the

(continued)

BASES

LCO (continued)

pressurization limit of SR 3.7.2.4 can be met. However, it is acceptable for access doors to be open for normal control room envelope entry and exit and not consider it to be a failure to meet the LCO.

APPLICABILITY

In MODES 1, 2, and 3, the CREF 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 due to the pressure and temperature limitations in these MODES. Therefore, maintaining the CREF System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

a. During movement of irradiated fuel assemblies in the secondary containment;

b. During CORE ALTERATIONS; and

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

ACTIONS

A.1

With one CREF subsystem inoperable, or with both CREF subsystems inoperable but the CREF System safety function maintained, the inoperable CREF subsystem(s) must be restored to OPERABLE status within 7 days. The CREF System safety function is maintained when the CREF System components equivalent to one CREF subsystem are OPERABLE. With the unit in this condition, the remaining OPERABLE CREF subsystem (or OPERABLE components in both subsystems) is adequate to perform the control room envelope radiation protection function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem (or remaining OPERABLE portions of the subsystems, as applicable) could result in loss of CREF System function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining subsystem (or components in both subsystems) can provide the required capabilities.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable CREF subsystem(s) 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.

C.1, C.2.1, C.2.2, and C.2.3

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 Required Actions of Condition C are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, if the inoperable CREF subsystem(s) cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE components of the CREF subsystem(s) equivalent to a single CREF subsystem (e.g., the CROASFT and fan portion of the air conditioning units do not have to be powered from the same electrical division) may be placed in the emergency pressurization mode. This action ensures that the remaining subsystem (or components in both subsystems equivalent to a single CREF subsystem) is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected. 1B

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room envelope. This places the unit in a condition that minimizes risk.

(continued)

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until the OPDRVs are suspended.

D.1

If both CREF subsystems are inoperable with the CREF System safety function not maintained in MODE 1, 2, or 3, the CREF System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

E.1, E.2, and E.3

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 Required Actions of Condition E are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, with two CREF subsystems inoperable with the CREF System safety function not maintained, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the control room envelope. This places the unit in a condition that minimizes risk.

(continued)

BASES

ACTIONS

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

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

Operating (from the control room) each CREF subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, filter booster or air conditioning unit fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain humidity, as necessary) for ≥ 10 continuous hours every 31 days reduces moisture on the adsorbers and HEPA filters. In addition, it is not necessary to operate all components of a single subsystem simultaneously for the 10 hour period. It is acceptable to operate the fan portion of the air conditioning unit(s) of one subsystem with the CROASFT of the other subsystem, such that the CROASFTs and fan portion of the air conditioning units are each operated for 10 continuous hours. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

SR 3.7.2.2

This SR verifies that the required CROASFT testing is performed in accordance with Specification 5.5.7, "Ventilation Filter Testing Program (VFTP)." The CROASFT filter tests are in accordance with Regulatory Guide 1.52 (Ref. 8). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.3

This SR verifies that each CREF subsystem starts and operates on an actual or simulated initiation signal. This SR also includes ensuring the air conditioning units (fan portion only) start on a low flow signal after the appropriate time delay. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.7.1, "Control Room Envelope Filtration (CREF) System Instrumentation," overlaps this SR to provide complete testing of the safety function. Operating experience has shown that these components normally pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was found to be acceptable from a reliability standpoint. B

SR 3.7.2.4

This SR verifies the integrity of the control room envelope and the assumed inleakage rates of potentially contaminated air. The control room envelope positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper function of the CREF System. The SR requires all combinations of the CREF System to be verified. This can be met by determining (by test) the worst combination of the air conditioning units (fan portion only), then testing the worst combination of the air conditioning units (fan portion only) with each CROASFT. During the emergency pressurization mode of operation, the CREF System is designed to slightly pressurize the control room envelope to ≥ 0.125 inches water gauge positive pressure with respect to outside atmosphere to prevent unfiltered inleakage. The CREF System is designed to maintain this positive pressure at an outside air intake flow rate of ≤ 1500 cfm to the control room envelope in the emergency pressurization mode. Compliance with this SR is demonstrated by measurement of the pressure in the control room and relay room, which are representative of adequate positive pressure in both elevations of the control room envelope. The Frequency of 24 months on a STAGGERED TEST BASIS is consistent with industry practice and other filtration system SRs. B

REFERENCES

1. USAR, Section 6.4.2.1.
2. NUREG-0800, Table 6.4-1. B

(continued)

BASES

REFERENCES (continued)

3. USAR, Section 6.4.1. B
4. USAR, Section 9.4.1. B
5. USAR, Chapter 6. B
6. USAR, Chapter 15. B
7. 10 CFR 50.36(c)(2)(ii). B
8. Regulatory Guide 1.52, Revision 2, March 1978. B

B 3.7 PLANT SYSTEMS

B 3.7.3 Control Room Envelope Air Conditioning (AC) System

BASES

BACKGROUND

The control room envelope AC portion of the Control Building Heating, Ventilation, and Air Conditioning (HVAC) System (hereafter referred to as the Control Room Envelope AC System) provides temperature control for the control room envelope following isolation of the control room envelope.

The Control Room Envelope AC System consists of two independent, redundant subsystems that provide cooling of recirculated and outside air makeup control room envelope air. Each subsystem consists of two air conditioning units (one for the control room and one for the relay room), one control building chilled water subsystem (which provides cooling water to the cooling coils of the two air conditioning units), ductwork, dampers, and instrumentation and controls to provide for control room envelope temperature control. Each air conditioning unit includes an air filter assembly, cooling coil, and fan. Each control building chilled water subsystem includes a hermetic centrifugal water chiller, chilled water pump, expansion tank, controls, piping, and valves.

The Control Room Envelope AC System is designed to provide a controlled environment under both normal and accident conditions. A single subsystem provides the required temperature control to maintain a suitable control room envelope environment for a sustained occupancy of 37 persons. The design conditions for the control room envelope environment are 75°F and 50% relative humidity. The Control Room Envelope AC System operation in maintaining the control room envelope temperature is discussed in the USAR, Sections 6.4 and 9.4.1 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The design basis of the Control Room Envelope AC System is to maintain the control room envelope temperature for a 30 day continuous occupancy following isolation of the control room envelope.

The Control Room Envelope AC System components are arranged in redundant safety related subsystems. During emergency operation, the Control Room Envelope AC System maintains a habitable environment and ensures the OPERABILITY of

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BASES

APPLICABLE SAFETY ANALYSES (continued)

components in the control room envelope. A single active failure of a component of the Control Room Envelope AC System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room envelope temperature control. The Control Room Envelope AC System is designed in accordance with Seismic Category I requirements. The Control Room Envelope AC System is capable of removing sensible and latent heat loads from the control room envelope, including consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY.

The Control Room Envelope AC System satisfies Criterion 3 of Reference 3.

LCO

Two independent and redundant subsystems of the Control Room Envelope AC System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in the equipment operating temperature exceeding limits.

The Control Room Envelope AC System is considered OPERABLE when the individual components necessary to maintain the control room envelope temperature are OPERABLE in both subsystems. These components include the control room and relay room air conditioning units (cooling coils and fans only), the control building chilled water subsystems, ductwork, dampers, and associated instrumentation and controls. In addition, during conditions in MODES other than MODES 1, 2, and 3 when the Control Room Envelope AC System is required to be OPERABLE (e.g., during CORE ALTERATIONS), the necessary portions of the SW System and Ultimate Heat Sink capable of providing cooling to the hermetic centrifugal water chillers are part of the OPERABILITY requirements covered by this LCO.

APPLICABILITY

In MODE 1, 2, or 3, the Control Room Envelope AC System must be OPERABLE to ensure that the control room envelope temperature will not exceed equipment OPERABILITY limits following control room envelope isolation.

In MODES 4 and 5, the probability and consequences of a Design Basis Accident are reduced due to the pressure and

(continued)

BASES

APPLICABILITY (continued)

temperature limitations in these MODES. Therefore, maintaining the Control Room Envelope AC System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

a. During movement of irradiated fuel assemblies in the secondary containment;

b. During CORE ALTERATIONS; and

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

ACTIONS

A.1

With one control room envelope AC subsystem inoperable, or with both control room envelope AC subsystems inoperable but the Control Room Envelope AC System safety function maintained, the inoperable control room envelope AC subsystem(s) must be restored to OPERABLE status within 30 days. The Control Room envelope AC System safety function is maintained when the Control Room Envelope AC System components equivalent to one control room envelope AC subsystem are OPERABLE. With the unit in this condition, the remaining OPERABLE control room envelope AC subsystem (or OPERABLE components in both subsystems) is adequate to perform the control room envelope air conditioning function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem (or remaining OPERABLE portions of the subsystems, as applicable) could result in loss of the control room envelope air conditioning function. The 30 day Completion Time is based on the low probability of an event occurring requiring control room envelope isolation, the consideration that the remaining subsystem (or components in both subsystems) can provide the required protection, and the availability of alternate cooling methods.

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable control room envelope AC subsystem(s) 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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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.

C.1, C.2.1, C.2.2, and C.2.3

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 Required Actions of Condition C are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, if Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE components of the control room envelope AC subsystem(s) equivalent to a single control room envelope AC subsystem (e.g., the control building chilled water subsystem and air conditioning units do not have to be powered from the same electrical division) may be placed immediately in operation. This action ensures that the remaining subsystem (or components in both subsystems equivalent to a single control room envelope AC subsystem) is OPERABLE, that no failures that would prevent actuation will occur, and that any active failure will be readily detected. B

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room envelope. This places the unit in a condition that minimizes risk.

(continued)

BASES

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until the OPDRVs are suspended.

D.1

If both control room envelope AC subsystems are inoperable with the Control Room Envelope AC System safety function not maintained in MODE 1, 2, or 3, the Control Room Envelope AC System may not be capable of performing the intended function. Therefore, LCO 3.0.3 must be entered immediately.

E.1, E.2, and E.3

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 Required Actions of Condition E are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs with two control room envelope AC subsystems inoperable with the Control Room Envelope AC System safety function not maintained, action must be taken to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room envelope. This places the unit in a condition that minimizes risk.

(continued)

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.2 (cont'd) such, 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.

LD.1 The Frequency for performing CTS 4.7.3.e.2 (proposed SR 3.7.2.3 and SR 3.7.2.4) has been extended from 18 months to 24 months. This SR ensures that each CROASFT is capable of automatic initiation and that the mechanical components operate as designed on system actuation (e.g., fans start, valves and dampers open or close as required)(see Discussion of Change M.1 for additional signal tested in proposed SR 3.7.2.3), and that the control room envelope boundary leakage is within the capacity of the CREF System by demonstrating that control room envelope can be maintained at a positive pressure with respect to outside atmosphere when in the emergency pressurization mode of operation.

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 4.0.2 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 4.0.2 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. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance 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 small.

The CREF System will be tested every 31 days according to proposed SR 3.7.2.1, therefore, any significant mechanical component failures will be detected and repaired during plant operation. This more frequent testing, although it does not test the actual initiation signal, verifies the OPERABILITY of the majority of the CREF System circuitry. Furthermore, as stated in the NRC Safety Evaluation Report (dated August 2, 1993) related to extension of the Peach Bottom Atomic Power Station, Unit Numbers 2 and 3, surveillance intervals from 18 to 24 months:

> "Industry reliability studies for boiling water reactors (BWRs), prepared by the BWR Owners Group (NEDC-30936P) show that the overall safety systems' reliabilities are not dominated by the reliabilities of the logic system, but by that of the mechanical components, (e.g., pumps and valves), which are consequently tested on a more frequent

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) basis. Since the probability of a relay or contact failure is small relative to the probability of mechanical component failure, increasing the logic system functional test interval represents no significant change in the overall safety system unavailability." B

Extending the surveillance interval for the verification of control room envelope boundary integrity is acceptable because the control room envelope boundary is maintained at a positive pressure during normal operation. Therefore, any substantial degradation of the boundary that would prevent maintaining the control room envelope at the required pressure during an accident will be evident prior to the scheduled performance of these tests. B

Based on the above discussion and on results of the review of the historical maintenance and surveillance data, the impact, if any, of this change on system availability is small. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis. B

"Specific"

L.1 CTS 3.7.3 Actions a and b.1 provides a 7 day restoration time when one CREF subsystem is inoperable. The CTS does not provide a restoration time when both CREF subsystems are inoperable; either LCO 3.0.3 must be entered (if in MODE 1, 2, or 3) or the CTS 3.7.3 Action b.2 must be taken (during Core Alterations, handling irradiated fuel, or OPDRVs). ITS 3.7.2 ACTION A will allow a 7 day restoration time when both CREF subsystems are inoperable, provided the CREF System safety function is maintained. ITS 3.7.2 ACTION D will require entry into 3.0.3 (if in MODE 1, 2, or 3) and ITS 3.7.2 ACTION E will require the unit to suspend Core Alterations, handling irradiated fuel, and OPDRVs (if performing one of these evolutions), if both CREF subsystems are inoperable and CREF System safety function is not maintained. The NMP2 CREF System design includes two filter trains and four air handling unit fans. The filter trains provides the means of filtering the control room envelope recirculated and outside air makeup. The filter train booster fans, which are considered part of the filter trains, take a suction on the filter train and provide sufficient head to overcome the differential pressure loss as a result of the filter trains being in service. The filter train booster fans discharge into a common header. The air handling unit fans take a suction on the common header and provide the necessary head to pressurize the control room envelope to 1/8 inch positive pressure. Two air handling unit fans are necessary to provide the 1/8 inch positive pressure; one for the control room area and one for the relay room. Thus for the CREF System to perform its

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) design function, one filter train and two air handling unit fans are required. Two CREF subsystems are provided, with each subsystem consisting of one filter train and two air handling unit fans, all from the same electrical power division. Due to this design, when both subsystems are inoperable, the capability for the CREF System to perform its design function may still exist. For example, if the Division 1 filter train and the Division 2 relay room air handling unit fan are inoperable, sufficient components are OPERABLE for the CREF System to meet its safety function (using the Division 2 filter train, the Division 1 relay room air handling unit fan, and either the Division 1 or 2 control room area air handling unit fan). Therefore, since this alignment is equivalent to having one CREF subsystem fully OPERABLE, the 7 day restoration time is acceptable, provided the CREF System safety function is maintained. The 7 day restoration time is identical to that already allowed in the CTS when one CREF subsystem is inoperable. In the current condition allowed by the CTS, the remaining OPERABLE subsystem will perform the CREF System safety function, assuming no additional single failure. The proposed condition will still ensure the remaining OPERABLE components of the two subsystems can perform the CREF safety function, assuming no additional single failure. If the remaining components of the CREF subsystems cannot maintain the CREF System safety function, then the unit will be required to enter LCO 3.0.3 (if in MODE 1, 2, or 3), or the unit must suspend Core Alterations, handling irradiated fuel, and OPDRVs (if performing one of these evolutions), consistent with the current requirements. In addition, this concept is consistent with the ECCS Specification in NUREG-1430, NUREG-1431, and NUREG-1432, which allow multiple ECCS trains to be inoperable for the same length of time as is currently allowed for one train only, provided 100% of the flow equivalent to a single ECCS train is available.

Due to this change, CTS 3.7.3 Action b.1 (ITS 3.7.2 Required Action C.1) has been revised to require the Operable components of CREF subsystem(s) equivalent to a single CREF subsystem to be placed in operation in lieu of placing the Operable subsystem in operation. The purpose of the current Action to place the subsystem in operation, is to ensure that the remaining subsystem is Operable, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected. Since this change does not impact the purpose of the Action (the three listed reasons remain valid), this portion of the change is acceptable.

L.2 CTS 3.7.3 Action b.1 provides the appropriate actions when one CREF subsystem is inoperable during movement of irradiated fuel in the secondary containment, Core Alterations, and OPDRVs. The Action requires the CREF subsystem to be restored in 7 days, or the Operable CREF subsystem must be placed and maintained in the emergency pressurization mode of operation. It further exempts the requirements of LCO 3.0.4 provided one Operable CREF

TECHNICAL CHANGES - LESS RESTRICTIVE

L.2 (cont'd) subsystem is in operation. This allowance precludes starting of the above listed evolutions when a CREF subsystem is inoperable unless the Operable subsystem is in operation; the evolutions cannot be started using the 7 day restoration time provided in the Action. This requirement has been deleted in ITS 3.7.2. This will allow the evolutions to be started and continued for up to 7 days before requiring the Operable CREF subsystem to be placed in operation. When this is done, there is still an Operable CREF subsystem that will automatically start when required. This change is consider to be acceptable since 1) it has been determined that a 7 day allowed out of service time for one CREF subsystem is acceptable, and 2) one CREF subsystem is still OPERABLE. Therefore, the deletion of the ITS LCO 3.0.4 exception is considered to provide no significant impact on safety.

L.3 CTS 4.7.3.b requires the CREF System to be operated every 31 days on a STAGGERED TEST BASIS. Proposed SR 3.7.2.1 does not include the STAGGERED TEST BASIS requirement. The intent of a requirement for staggered testing is to increase reliability of the component/system being tested. A number of reviews/evaluations have been performed which have demonstrated that staggered testing has negligible impact on component reliability. As a result, it has been determined that staggered testing 1) is operationally difficult, 2) has negligible impact on component reliability, 3) is not as significant as initially thought, and 4) has no impact on failure frequency. Therefore, the CREF staggered testing requirements have been deleted. Since the Frequency is not affected, i.e., both CTS and ITS require monthly testing for each subsystem, and staggered testing has a negligible impact on component reliability, this requirement has been deleted.

L.4 The phrase "actual or," in reference to the actuation test signal in CTS 4.7.3.e.2, has been added to proposed SR 3.7.2.3, which verifies that each CREF subsystem actuates on an actuation test signal (see Discussion of Change M.1 for additional signal tested in proposed SR 3.7.2.3). This allows satisfactory automatic CREF System initiations for other than surveillance purposes to be used to fulfill the Surveillance Requirement. Operability is adequately demonstrated in either case since the CROASFT subsystem itself cannot discriminate between "actual" or "test" signals.

INSERT ACTIONS-2

BASES

ACTIONS (continued)

C.1 and C.2

any Required Action and

If the [SSW] subsystem cannot be restored to OPERABLE status within the associated Completion Time, or both SSW subsystems are inoperable for reasons other than Condition A, or the UHS is determined inoperable for reasons other than Condition A, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

of Condition A, B, C, D, E, or F are not met

B, and C

INSERT ACTION G NOTE

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

Insert SR 3.7.1.1

This SR ensures adequate long term (30 days) cooling can be maintained. With the [UHS] water source below the minimum level, the affected [SSW] subsystem must be declared inoperable. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

However, if a SW subsystem supply header water temperature is ≥ 75°F, the Surveillance must be performed more frequently (every 4 hours if ≥ 75°F and every 2 hours if ≥ 79°F), since the condition is closer to the maximum water temperature limit.

SR 3.7.1.2

This SR verifies the water level in the each SSW pump well of the intake bay the intake structure to be sufficient for the proper operation of the SSW pumps (net positive suction head and pump vortexing are considered in determining this limit). The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

The water level limit, 233.1 ft, is referenced to mean sea level.

SR 3.7.1.3

each SW subsystem supply header

Verification of the [UHS] temperature ensures that the heat removal capability of the SSW System is within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

(continued)

BACKGROUND

The [CRFA] System provides a radiologically controlled environment from which the unit can be safely operated following a Design Basis Accident (DBA).

The safety related function of the [CRFA] System used to control radiation exposure consists of two independent and redundant high efficiency air filtration subsystems for treatment of recirculated air or outside supply air. Each subsystem consists of a demister, an electric heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a second HEPA filter, a fan, and the associated ductwork and dampers. Demisters remove water droplets from the airstream. Prefilters and HEPA filters remove particulate matter that may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay.

In addition to the safety related standby emergency filtration function, parts of the [CRFA] System are operated to maintain the control room environment during normal operation. Upon receipt of the initiation signal(s) (indicative of conditions that could result in radiation exposure to control room personnel), the [CRFA] System automatically switches to the isolation mode of operation to prevent infiltration of contaminated air into the control room. A system of dampers isolates the control room, and control room air flow is recirculated and processed through either of the two filter subsystems.

The [CRFA] System is designed to maintain the control room environment for a 30 day continuous occupancy after a DBA, without exceeding a 5 rem whole body dose or its equivalent to any part of the body. [CRFA] System operation in maintaining the control room habitability is discussed in the FSAR, Sections {6.8.1} and {9.4.1} (Refs. 1 and 8, respectively).

(continued)

3 INSERT BACK-1

The control room envelope consists of all rooms and areas located in the main control room and relay room of the control building. Included in the envelope are the main control room, relay room, instrument shop, training room, shift supervisor's office, lunch room, toilets, corridors, work release room, and HVAC equipment rooms (Ref. 1).

3 INSERT BACK-2

includes a control room outdoor air special filter train (CROASFT), which consists of

3 INSERT BACK-3

Each subsystem also includes the necessary outside air intake(s) and two air conditioning units (fan portion only), one for the control room and one for the relay room. Each outside air intake is capable of providing 100% of the necessary makeup flow. Therefore, normally only one outside air intake is necessary. However, when the unit is in MODE 1, 2, or 3 with MSIV leakage > 15 scfh for any MSIV, both outside air intakes, including the capability to isolate the intakes, are necessary. Both outside air intakes are required in these conditions since the accident analysis assumes the most contaminated outside air intake is isolated 8 hours after the accident to ensure the dose to control room envelope personnel does not exceed the limit. The outside air intake that is not isolated continues to be capable of providing 100% of the necessary makeup flow. The two required outside air intakes are allowed to be common to both subsystems (since there are only two outside air intakes for the CREF System). Alternately, if MSIV leakage is > 15 scfh for any MSIV, an additional analysis may be performed to determine the "effective" MSIV leakage. The "effective" MSIV leakage is the individual MSIV leak rate when all four main steam lines are assumed to leak at the same rate, and the doses in the control room envelope are equivalent to those when the individual "as-left" valve leak rates are used. If the "effective" MSIV leakage is $\leq$ 15 scfh, then only one outside air intake is necessary.

3 INSERT BACK-4

CROASFTs. In addition, a portion of the control room air is recirculated through the CROASFTs. The air conditioning units (fan portion only) maintain the 1/8 inch positive pressure; the CROASFT booster fan only provides the motive force to overcome the added resistance of the CROASFT being in service.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The ability of the [CRFA] System to maintain the habitability of the control room is an explicit assumption for the safety analyses presented in the FSAR, Chapters {6} and {15} (Refs. 5 and 6, respectively). The isolation mode of the [CRFA] System is assumed to operate following a loss of coolant accident, main steam line break, fuel handling accident, and control rod drop accident. The radiological doses to control room personnel as a result of the various DBAs are summarized in Reference 4. No single active or passive failure will cause the loss of outside or recirculated air from the control room.

The [CRFA] System satisfies Criterion 3 of the NRC Policy Statement.

LCO

Two redundant subsystems of the [CRFA] System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in exceeding a dose of 5 rem to the control room operators in the event of a DBA.

The [CRFA] System is considered OPERABLE when the individual components necessary to control operator exposure are OPERABLE in both subsystems. A subsystem is considered OPERABLE when its associated:

a. Fan is OPERABLE;
b. HEPA filter and charcoal adsorber are not excessively restricting flow and are capable of performing their filtration functions; and
c. Heater, demister, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

In addition, the control room boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors.

APPLICABILITY

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

(continued)

6 INSERT ACTION C.1a

Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

7 INSERT ACTION C.1b

(s) equivalent to a single CREF subsystem (e.g., the CROASFT and fan portion of the air conditioning units do not have to be powered from the same electrical division) B

7 INSERT ACTION C.1c

(or components in both subsystems equivalent to a single CREF subsystem)

6 INSERT E.1, E.2, and E.3

Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

6 INSERT SR 3.7.2.1

Operating (from the control room) each CREF subsystem for ≥ 10 continuous hours ensures that both subsystems are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, filter booster or air conditioning unit fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain humidity, as necessary) for ≥ 10 continuous hours every 31 days reduces moisture on the adsorbers and HEPA filters. In addition, it is not necessary to operate all components of a single subsystem simultaneously for the 10 hour period. It is acceptable to operate the fan portion of the air conditioning unit(s) of one subsystem with the CROASFT of the other subsystem, such that the CROASFTs and fan portion of the air conditioning units are each operated for 10 continuous hours. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

1 B

3 B

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1 (continued)

each subsystem once every month provides an adequate check on this system. Monthly heater operation dries out any moisture accumulated in the charcoal from humidity in the ambient air. [Systems with heaters must be operated for ≥ 10 continuous hours with the heaters energized. Systems without heaters need only be operated for ≥ 15 minutes to demonstrate the function of the system.] Furthermore, the 31 day frequency is based on the known reliability of the equipment and the two subsystem redundancy available.

SR 3.7.3.2

This SR verifies that the required CREA testing is performed in accordance with the {Ventilation Filter Testing Program (VFTP)}." The CREA filter tests are in accordance with Regulatory Guide 1.52 (Ref. 3). The {VFTP} includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the {VFTP}.

SR 3.7.3.3

This SR verifies that each [CRFA] subsystem starts and operates on an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.7.5 overlaps this SR to provide complete testing of the safety function. The [18] month frequency is specified in Reference 5.

SR 3.7.3.4

This SR verifies the integrity of the control room enclosure and the assumed inleakage rates of potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper function of the [CRFA] System. During the emergency mode of operation, the [CRFA] System is designed to slightly pressurize the control room to {0.1} inches water gauge positive pressure with respect to adjacent areas to prevent unfiltered inleakage. The [CRFA]

(continued)

Compliance with this SR is demonstrated by measurement of the pressure in the control room and relay room, which are representative of adequate positive pressure in both elevations of the control room envelope.

CREF

[CRFA] System
B 3.7.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4 (continued)

System is designed to maintain this positive pressure at an flow rate of [500] cfm to the control room in the [isolation] mode. The Frequency of [18] months on a STAGGERED TEST BASIS is consistent with industry practice and other filtration system SRs.

≤ 1500

envelope

outside air intake

emergency pressurization

24

REFERENCES

1. USAR, Section 6.4.2.1.
2. NUREG-0800, Table 6.4-1.

1. USAR, Section [6.2.1].
2. USAR, Section [9.4.1].
3. USAR, Chapter [6].
4. USAR, Chapter [15].
5. Regulatory Guide 1.52, Revision 2, March 1978.
6. 10 CFR 50.36 (c) (2) (ii).

B 3.7 PLANT SYSTEMS

B 3.7.[illegible] {Control Room Air Conditioning (AC)} System

BASES

BACKGROUND

The {Control Room AC} System provides temperature control for the control room following isolation of the control room.

The {Control Room AC} System consists of two independent, redundant subsystems that provide cooling and heating of recirculated control room air. Each subsystem consists of heating coils, cooling coils, fans, chillers, compressors, ductwork, dampers, and instrumentation and controls to provide for control room temperature control.

The {Control Room AC} System is designed to provide a controlled environment under both normal and accident conditions. A single subsystem provides the required temperature control to maintain a suitable control room environment for a sustained occupancy of 12 persons. The design conditions for the control room environment are 70°F and 50% relative humidity. The {Control Room AC} System operation in maintaining the control room temperature is discussed in the FSAR, Sections {6.4} and {9.4.1} (Refs: 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The design basis of the {Control Room AC} System is to maintain the control room temperature for a 30 day continuous occupancy.

The {Control Room AC} System components are arranged in redundant safety related subsystems. During emergency operation, the {Control Room AC} System maintains a habitable environment and ensures the OPERABILITY of components in the control room. A single active failure of a component of the {Control Room AC} System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The {Control Room AC} System is designed in accordance with Seismic Category I requirements. The {Control Room AC} System is capable of removing sensible and latent heat loads from the control room, including consideration of equipment

(continued)

3 INSERT BKGRD

Each air conditioning unit includes an air filter assembly, cooling coil, and fan. Each control building chilled water subsystem includes a hermetic centrifugal water chiller, chilled water pump, expansion tank, controls, piping, and valves. 1B

BASES

APPLICABLE SAFETY ANALYSES (continued)

heat loads and personnel occupancy requirements to ensure equipment OPERABILITY.

The {Control Room AC} System satisfies Criterion 3 of the NRC Policy Statement.

LCO

Two independent and redundant subsystems of the {Control Room AC} System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in the equipment operating temperature exceeding limits.

The {Control Room AC} System is considered OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both subsystems. These components include the cooling coils, fans, chillers, compressors, ductwork, dampers, and associated instrumentation and controls.

APPLICABILITY

In MODE 1, 2, or 3, the {Control Room AC} System must be OPERABLE to ensure that the control room temperature will not exceed equipment OPERABILITY limits following control room isolation.

In MODES 4 and 5, the probability and consequences of a Design Basis Accident are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the {Control Room AC} System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

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

b. During CORE ALTERATIONS; and

c. During movement of irradiated fuel assemblies in the {primary or} secondary containment};

(continued)

5 INSERT LCO

In addition, during conditions in MODES other than MODES 1, 2, and 3 when the Control Room Envelope AC System is required to be OPERABLE (e.g., during CORE ALTERATIONS), the necessary portions of the SW System and Ultimate Heat Sink capable of providing cooling to the hermetic centrifugal water chillers are part of the OPERABILITY requirements covered by this LCO. 1B

7 INSERT ACTION A.1a

or with both control room envelope AC subsystems inoperable but the Control Room Envelope AC System safety function maintained,

7 INSERT ACTION A.1b

The Control Room envelope AC System safety function is maintained when the Control Room Envelope AC System components equivalent to one control room envelope AC subsystem are OPERABLE.

7 INSERT ACTION A.1c

(or OPERABLE components in both subsystems)

7 INSERT ACTION A.1d

(or components in both subsystems)

4 INSERT ACTION C.1a

Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

7 INSERT ACTIONS C.1b

(s) equivalent to a single control room envelope AC subsystem (e.g., the control building chilled water subsystem and air conditioning units do not have to be powered from the same electrical division) 13

Volume 9
Section 3.8

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.2	----------NOTE---------- All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. ---------- Verify each required DG starts from standby conditions and achieves: a. In ≤ 10 seconds, voltage ≥ 3950 V for Division 1 and 2 DGs and ≥ 3820 V for Division 3 DG, and frequency ≥ 58.8 Hz for Division 1 and 2 DGs and ≥ 58.0 Hz for Division 3 DG; and b. Steady state voltage ≥ 3950 V and ≤ 4370 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ----------	
	Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2 only; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 13.20 seconds, 2. energizes auto-connected shutdown loads for Division 1 and 2 DGs only, 3. maintains steady state voltage ≥ 3950 V and ≤ 4370 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes for Division 1 and 2 DGs and supplies permanently connected shutdown loads for ≥ 5 minutes for Division 3 DG.	24 months

(continued)

Table 3.8.6-1 (page 1 of 1)
Battery Cell Parameter Requirements

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: LIMITS FOR EACH CONNECTED CELL
Electrolyte Level	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[a]	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[a]	Above top of plates, and not overflowing
Float Voltage	≥ 2.13 V	≥ 2.13 V	> 2.07 V
Specific Gravity[b][c]	≥ 1.200	≥ 1.195 <u>AND</u> Average of all connected cells > 1.205	Not more than 0.020 below average of all connected cells <u>AND</u> Average of all connected cells ≥ 1.195

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during and following equalizing charges provided it is not overflowing.

(b) Corrected for electrolyte temperature and level.

(c) A battery charging current of < 2 amps when on float charge is acceptable for meeting specific gravity limits following a battery recharge, for a maximum of 7 days. When charging current is used to satisfy specific gravity requirements, specific gravity of each connected cell shall be measured prior to expiration of the 7 day allowance.

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

AC sources satisfy the requirements of Criterion 3 of Reference 7.

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System, and three separate and independent DGs, ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the USAR and are part of the licensing basis for the unit.

Each offsite circuit from the 345 kV/115 kV Scriba Substation must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the 4.16 kV emergency buses. Each offsite circuit consists of the incoming breaker and disconnect to the respective reserve station service transformers 2RTX-XSR1A and 2RTX-XSR1B and auxiliary boiler transformer 2ABS-X1, the respective 2RTX-XSR1A, 2RTX-XSR1B, and 2ABS-X1 transformers, and the respective circuit path including feeder breakers to the 4.16 kV emergency buses. In addition, proper sequencing of loads is a required function for offsite circuit OPERABILITY. B

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 13.20 seconds. The 13.20 second start time includes the Loss of Voltage—Time Delay Function Allowable Value specified in LCO 3.3.8.1. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the 4.16 kV emergency buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot and DG in standby with engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while

(continued)

BASES

ACTIONS

B.2 (continued)

required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG(s), SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs are declared inoperable upon discovery, and Condition E or G of LCO 3.8.1 is entered, as applicable. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the Deficiency Event Report Program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 9), 24 hours is reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

B.4

According to Regulatory Guide 1.93 (Ref. 8), operation may continue in Condition B for a period that should not exceed 72 hours. In this condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. B

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 3950 V is approximately 95% of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. 14), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90%, or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4370 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 11).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2

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

To minimize the wear on moving parts that do not get lubricated when the engine is not running, this SR has been modified by a Note to indicate that all DG starts for this Surveillance may be preceded by an engine prelube period. In

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 (continued)

addition, to minimize wear and tear on the DG, the Note also allows all DG starts to be followed by a warmup period prior to loading.

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant (Division 1 and 2 DGs only) and lube oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 3.8.1.2 requires that the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions in the design basis LOCA analysis (Ref. 15). In addition, the DG is required to maintain proper voltage and frequency limits after steady state is achieved. The voltage and frequency limits are normally achieved within 13 seconds for the Division 1 and 2 DGs and within 15 seconds for the Division 3 DG. The time for the DG to reach steady state operation is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 11). This Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance demonstrates 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

The DG auto-start and energization of permanently connected loads time of 13.20 seconds is derived from the 3.20 second Loss of Voltage—Time Delay Function Allowable Value (LCO 3.3.8.1) and the requirements of the accident analysis for responding to a design basis large break LOCA (Ref. 14). The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved. 1B

The requirement to verify the connection and power supply of permanently connected loads and auto-connected loads (Division 1 and 2 only) is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant (Division 1 and 2 DGs only) and lube oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.5, this Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal). In addition, the DG is required to maintain proper voltage and frequency limits after steady state is achieved. The voltage and frequency limits are normally achieved within 13 seconds for the Division 1 and 2 DGs and within 15 seconds for the Division 3 DG. The DG is required to operate for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.10.d and SR 3.8.1.10.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ECCS signal without loss of offsite power (for Divisions 1 and 2 only).

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. This is only required for Divisions 1 and 2 because the loading logic is different based on the power source. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the AC electrical power system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified. B

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with the expected fuel cycle lengths.

(continued)

BASES

LCO (continued)

a separate offsite circuit to the Division 3 Class 1E onsite electrical power distribution subsystem, or an OPERABLE Division 3 DG, ensures an additional source of power for the HPCS. This additional source for Division 3 is not necessarily required to be connected to be OPERABLE. Either the circuit required by LCO Item a., or a circuit required to meet LCO Item c. may be connected, with the second source available for connection. Together, OPERABILITY of the required offsite circuit(s) and DG(s) ensure the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents, reactor vessel draindown).

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to their respective emergency bus(es), and of accepting required loads during an accident. Qualified offsite circuits are those that are described in the USAR and are part of the licensing basis for the plant. The offsite circuit from the 345 kV/115 kV Scriba Substation consists of the incoming breaker and disconnect to the respective reserve station service transformers 2RTX-XSR1A and 2RTX-XSR1B and auxiliary boiler transformer 2ABS-X1, the respective 2RTX-XSR1A, 2RTX-XSR1B, and 2ABS-X1 transformers, and the respective circuit path including feeder breakers to all 4.16 kV emergency buses required by LCO 3.8.9.

The required DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective emergency bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 13.20 seconds. The start time includes the 3.20 second Loss of Voltage—Time Delay Function Allowable Value specified in LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation." Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the emergency buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

(continued)

BASES

LCO (continued)

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY. The necessary portions of the Service Water System and Ultimate Heat Sink capable of providing cooling to the required DG(s) are also required. In addition, proper sequencing of loads is a required function for offsite circuit OPERABILITY. B

It is acceptable for divisions to be cross tied during shutdown conditions, permitting a single offsite power circuit to supply all required divisions.

APPLICABILITY

The AC 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. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel 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.

The AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.

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 MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3 while in MODE 1, 2, or 3 would require the unit to be shutdown, but would not require

(continued)

BASES

ACTIONS (continued)

immediate suspension of movement of irradiated fuel assemblies. The Note to the ACTIONS, "LCO 3.0.3 is not applicable," ensures that the actions for immediate suspension of irradiated fuel assembly movement are not postponed due to entry into LCO 3.0.3.

A.1

An offsite circuit is considered inoperable if it is not available to one required 4.16 kV emergency bus. If two or more 4.16 kV emergency buses are required per LCO 3.8.9, division(s) 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 that are not powered from offsite power, appropriate restrictions can be implemented in accordance with the required feature(s) LCOs' ACTIONS. 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.

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. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and activities that could potentially result in inadvertent draining of the reactor vessel.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to initiate action immediately to restore the required AC sources and to

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4
(continued)

continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required emergency bus, ACTIONS for LCO 3.8.9 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.9 provides the appropriate restrictions for the situation involving a de-energized division.

C.1

When the HPCS System is required to be OPERABLE, and the additional required Division 3 AC source is inoperable, the required diversity of AC power sources to the HPCS System is not available. Since these sources only affect the HPCS System, the HPCS System is declared inoperable and the Required Actions of LCO 3.5.2, "Emergency Core Cooling Systems—Shutdown" entered.

In the event all sources of power to Division 3 are lost, Condition A will also be entered and direct that the ACTIONS of LCO 3.8.9 be taken. If only the Division 3 additional required AC source is inoperable, and power is still supplied to HPCS, 72 hours is allowed to restore the additional required AC source to OPERABLE. This is reasonable considering HPCS System will still perform its function, absent an additional single failure.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1 (continued)

sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory (above the manufacturers minimum recommended level) is available to support at least 7 days of full load operation for each DG. The 99 gallon requirement for the Division 1 and 2 DGs and the 168 gallon requirement for the Division 3 DG are based on the DG manufacturer's consumption values for the run time of the DG. The 7 day inventory can be in the engine oil sump or a combination of the engine oil sump and remote storage location. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage location to the DG when the DG lube oil sumps do not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level. B

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run times are closely monitored by the plant staff.

SR 3.8.3.3

The tests of new fuel oil prior to addition to the storage tanks are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion and operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

A battery modified performance discharge test is a simulated duty cycle normally consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance discharge test, both of which envelope the duty cycle of the service test. (The test can consist of a single rate if the test rate employed for the performance discharge test exceeds the 1 minute rate.) Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery performance discharge test for the duration of time equal to that of the performance discharge test.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a performance discharge test. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 9) and IEEE-485 (Ref. 11). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturers rating, since IEEE-485 (Ref. 11) recommends using an aging factor of 125%

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

specified for specific gravity for each connected cell is ≥ 1.195 (0.020 below the manufacturers fully charged, nominal specific gravity) with the average of all connected cells > 1.205 (0.010 below the manufacturers fully charged, nominal specific gravity). These values are based on manufacturers recommendations. The minimum specific gravity value required for each cell ensures that a cell with a marginal or unacceptable specific gravity is not masked by averaging with cells having higher specific gravities.

Category C defines the limit for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limit, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensures that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limit for float voltage is based on IEEE-450, Appendix C (Ref. 4), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity (≥ 1.195), is based on manufacturers recommendations (0.020 below the manufacturers recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no more than 0.020 below the average of all connected cells. This limit ensures that a cell with a marginal or unacceptable specific gravity is not masked by averaging with cells having higher specific gravities.

The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity. Footnote b requires the above mentioned correction for electrolyte level and temperature. B

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charging current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 4). Footnote c allows the float charge current to be used as an alternate to specific gravity for up to 7 days following a battery recharge. Within 7 days each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than 7 days.

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 15 and Appendix A.
3. 10 CFR 50.36(c)(2)(ii).
4. IEEE Standard 450, 1980.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR, Chapter 6 (Ref. 1) and Chapter 15 and Appendix A (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and 120 VAC uninterruptible 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, DC, and 120 VAC uninterruptible electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the AC and DC electrical power sources and associated distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite or onsite AC electrical power; and

b. A worst case single failure.

The AC, DC, and 120 VAC uninterruptible electrical power distribution systems satisfy Criterion 3 of Reference 3.

LCO

The required AC, DC, and 120 VAC uninterruptible power distribution subsystems listed in Table B 3.8.8-1 ensure the availability of AC, DC, and 120 VAC uninterruptible electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The Division 1, 2, and 3 AC and DC, and Division 1 and 2 120 VAC uninterruptible electrical power primary distribution subsystems are required to be OPERABLE. As noted in Table B 3.8.8-1 (Footnote a), each division of the AC, DC, and 120 VAC uninterruptible electrical power distribution systems is a subsystem. B

Maintaining the Division 1, 2, and 3 AC and DC, and Division 1 and 2 120 VAC uninterruptible electrical power

(continued)

BASES

LCO (continued)

distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Any two of the three divisions of the distribution system are capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any system or within the electrical power distribution subsystems does not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE 120 VAC uninterruptible electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated emergency UPS inverter via inverted DC voltage, inverter using internal rectified AC source, or Class 1E regulating transformer.

Based on the number of safety significant electrical loads associated with each bus listed in Table B 3.8.8-1, if one or more of the buses becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.8 is required. Some buses, such as distribution panels, which help comprise the AC and DC distribution systems are not listed in Table B 3.8.8-1. The loss of electrical loads associated with these buses may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these buses become inoperable due to a failure not affecting the OPERABILITY of a bus listed in Table B 3.8.8-1 (e.g., a breaker supplying a single distribution panel fails open), the individual loads on the bus would be considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. However, if one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in Table B 3.8.8-1 (e.g., loss of a 4.16 kV emergency bus, which results in de-energization of all buses powered from the 4.16 kV emergency bus), then although the individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since

(continued)

BASES

LCO (continued)

LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4.16 kV emergency bus).

In addition, tie breakers between Division 1 and Division 2 safety related AC power distribution subsystems must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the electrical power distribution subsystems that are not being powered from their normal source (i.e., they are being powered from their redundant electrical power distribution subsystems) are considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV emergency buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained, in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 4 and 5 and other conditions in which AC, DC, and 120 VAC uninterruptible electrical power distribution subsystems are required are covered in the Bases for LCO 3.8.9, "Distribution Systems—Shutdown."

ACTIONS

A.1

With one or more Division 1 and 2 required AC buses, load centers, motor control centers, or distribution panels (except 120 VAC uninterruptible panels) inoperable and a loss of function has not yet occurred, the remaining AC electrical power distribution subsystems are capable of

(continued)

BASES

ACTIONS

A.1 (continued)

supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

The Condition A worst scenario is one division without AC power (i.e., no offsite power to the division and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining division by stabilizing the unit and restoring power to the affected division. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected division to the actions associated with taking the unit to shutdown within this time limit.

b. The low potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.11, "Safety Function Determination Program (SFDP).")

The second Completion Time for Required Action A.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 3.8.8.a, b, or c. If Condition A is entered while, for instance, a DC electrical power distribution subsystem is inoperable and subsequently returned OPERABLE, LCO 3.8.8.a, b, or c may already have been not met for up to 2 hours. This situation could lead to a total duration of 10 hours, since initial failure of LCO 3.8.8.a, b, or c, to restore the AC electrical power

(continued)

BASES

ACTIONS

A.1 (continued)

distribution system. At this time, a DC bus could again become inoperable, and the AC electrical power distribution subsystem could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time LCO 3.8.8.a, b, or c was initially not met, instead of at the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet LCO 3.8.8.a, b, or c indefinitely.

B.1

With one or more Division 1 and 2 120 VAC uninterruptible panels inoperable and a loss of function has not yet occurred, the remaining 120 VAC uninterruptible panels are capable of supporting the minimum safety functions necessary to shut down and maintain the unit in the safe shutdown condition. Overall reliability is reduced, however, because an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the 120 VAC uninterruptible electrical power distribution subsystem(s) must be restored to OPERABLE status within 8 hours by powering the bus from the associated emergency UPS inverter via inverted DC, inverter using internal AC source/rectifier, or Class 1E regulating transformer.

Condition B worst scenario is one 120 VAC uninterruptible electrical power distribution subsystem without power; potentially both the DC source and the associated AC source nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all uninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining 120 VAC uninterruptible electrical power distribution subsystem, and restoring power to the affected 120 VAC uninterruptible electrical power distribution subsystem(s).

This 8 hour limit is more conservative than Completion Times allowed for the majority of components that are without adequate 120 VAC uninterruptible power. Taking exception to

(continued)

BASES

ACTIONS

B.1 (continued)

LCO 3.0.2 for components without adequate 120 VAC uninterruptible power, that would have Required Action Completion Times shorter than 8 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without adequate 120 VAC uninterruptible power, while not providing sufficient time for the operators to perform the necessary evaluations and actions to restore power to the affected division;

c. The potential for an event in conjunction with a single failure of a redundant component.

The 8 hour Completion Time takes into account the importance to safety of restoring the 120 VAC uninterruptible electrical power distribution subsystems to OPERABLE status, the redundant capability afforded by the remaining 120 VAC uninterruptible electrical power distribution subsystems, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.8.a, b, or c. If Condition B is entered while, for instance, an AC electrical power distribution subsystem is inoperable and subsequently returned OPERABLE, LCO 3.8.8.a, b, or c may already have been not met for up to 8 hours. This situation could lead to a total duration of 16 hours, since initial failure of LCO 3.8.8.a, b, or c, for restoring the 120 VAC uninterruptible electrical power distribution subsystems. At this time, an AC electrical power distribution subsystem could again become inoperable, and 120 VAC uninterruptible electrical power distribution subsystem could be restored to OPERABLE. This could continue indefinitely.

(continued)

BASES

ACTIONS

B.1 (continued)

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time LCO 3.8.8.a, b, or c was initially not met, instead of at the time that Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet LCO 3.8.8.a, b, or c indefinitely.

C.1

With one or more Division 1 and 2 DC buses inoperable and a loss of function has not yet occurred, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC electrical power distribution subsystem(s) must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition C worst scenario is one division without adequate DC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining division, and restoring power to the affected division(s).

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that could be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, that would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

(continued)

BASES

ACTIONS

C.1 (continued)

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without DC power while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC electrical power distribution subsystems is consistent with Regulatory Guide 1.93 (Ref. 4).

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.8.a, b, or c. If Condition C is entered while, for instance, an AC electrical power distribution subsystem is inoperable and subsequently returned OPERABLE, LCO 3.8.8.a, b, or c 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 3.8.8.a, b, or c, to restore the DC electrical power distribution system. 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 3.8.8.a, b, or c was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet LCO 3.8.8.a, b, or c indefinitely.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable electrical power distribution system cannot be restored to OPERABLE status within the associated Completion Times, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

With the Division 3 electrical power distribution system inoperable (i.e., one or both Division 3 AC and DC electrical power distribution subsystems inoperable), the Division 3 powered systems are not capable of performing their intended functions. Immediately declaring the High Pressure Core Spray System inoperable allows the ACTIONS of LCO 3.5.1, "ECCS—Operating," to apply appropriate limitations on continued reactor operation.

F.1

Condition F corresponds to a level of degradation in the electrical power distribution system that causes a required safety function to be lost (single division systems are not included, although for this ACTION, Division 3 is considered redundant to Division 1 and 2 ECCS). When two or more inoperable electrical power distribution subsystems result in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown. B

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC, DC, and 120 VAC uninterruptible electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1 (continued)

appropriate separation and independence of the electrical divisions is maintained, and power is available to each required bus. The verification of energization of the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This is normally performed by verifying correct voltage for the AC and DC switchgear and by verifying that no inoperability status indicator lights (that indicate a loss of power to one or more of the required load centers, motor control centers (MCCs), or distribution panels) are lit in the control room. Alternately, when the normal method is not available, verification that a load powered from the associated bus is energized is also acceptable. The 7 day Frequency takes into account the redundant capability of the AC, DC, and 120 VAC uninterruptible electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 15 and Appendix A.
3. Regulatory Guide 1.93, Revision 0, December 1974.
4. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal—shutdown cooling (RHR-SDC) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR-SDC inoperable, which results in taking the appropriate RHR-SDC ACTIONS.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the AC, DC, and 120 VAC uninterruptible electrical power distribution subsystems are functioning properly, with the correct breaker alignment. The correct breaker alignment ensures power is available to each required bus. The verification of energization of the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. This is normally performed by verifying correct voltage for the AC and DC switchgear and by verifying that no inoperability status indicator lights (that indicate a loss of power to one or more of the required load centers, MCCs, or distribution panels) are lit in the control room. Alternately, when the normal method is not available, verification that a load powered from the associated bus is energized is also acceptable. The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that alert the operator to subsystem malfunctions. B

REFERENCES

1. USAR, Chapter 6.

2. USAR, Chapter 15 and Appendix A.

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

A.1

Specification 3.8.1

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 AC SOURCES

AC SOURCES - OPERATING

LIMITING CONDITIONS FOR OPERATION

LCO 3.8.1

3.8.1.1 As a minimum, the following AC electrical power sources shall be OPERABLE: LA.1

LCO 3.8.1.a

a. Two physically independent (qualified) circuits between the offsite transmission network and the onsite Class 1E distribution system, and

LCO 3.8.1.b

b. Three separate and independent diesel generators, each with: LA.1

1. Separate day fuel tanks containing a minimum of 403 gallons of fuel for EDG*1 (Division I) and EDG*3 (Division II), and 282 gallons for EDG*2 (HPCS-Division III) A.2 SR 3.8.1.4

2. A separate fuel storage system containing a minimum of 47,547 gallons of fuel for EDG*1 (Division I) and EDG*3 (Division II), and 35,342 gallons for EDG*2 (HPCS-Division III), and A.3 Moved to LCO 3.8.3

3. Two fuel oil transfer pumps. LA.1 B A.4 L.2.2

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

add proposed Applicability Note

ACTION: M.1 M.2

add proposed Required Action A.2

add proposed Required Action A.3 2nd Completion Time

ACTION A

a. With one offsite circuit of the above required AC electrical power sources inoperable, demonstrate the OPERABILITY of the remaining AC sources by performing Surveillance Requirements 4.8.1.1.1 within 1 hour and at least once every 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. L.1

ACTION F

add proposed Required Action A.3 3rd Completion Time

ACTION B

b. With either diesel generator EDG*1 or EDG*3 inoperable, demonstrate the OPERABILITY of the above required AC offsite sources by performing Surveillance Requirement 4.8.1.1.1 within 1 hour and at least once every 8 hours thereafter. If the diesel generator became inoperable from any cause other than preplanned maintenance or testing, within 24 hours, for each OPERABLE diesel generator separately, either verify that the cause of the diesel generator being inoperable does not impact the OPERABILITY of the OPERABLE diesel generator or perform Surveillance Requirement 4.8.1.1.2.a.4*. Restore the inoperable diesel generator to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. L.2 L.1

ACTION F

add proposed Required Action B.4 2nd Completion Time

* This is required to be completed regardless of when the inoperable diesel generator is restored to OPERABLE status. The provisions of Specification 3.0.2 are not applicable.

L.2

Specification 3.8.1

A.1

ELECTRICAL POWER SYSTEMS

AC SOURCES

AC SOURCES - OPERATING

SURVEILLANCE REQUIREMENTS

4.8.1.1.2.a (Continued)

SR3.8.1.6 3. Verifying each fuel transfer pump starts and transfers fuel from the storage system to the day fuel tank every 92 days L.6

SR3.8.1.2 4. Verifying that on a start from ambient conditions: M.7

a) That diesel engines EDG*1 and EDG*3 accelerate to at least 600 rpm in less than or equal to 10 seconds.* The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 3.0 Hz within 10 seconds and 4160 ± 416 volts and 60 ± 1.2 Hz ~~within 13 seconds after the start signal~~. 210 1.2 L.7 210 M.7 L.8 LA.3

b) That diesel engine EDG*2 accelerates to at least 870 rpm and at least 3950 volts in less than or equal to 10 seconds.* The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 1.2 Hz ~~within 15 seconds after the start signal~~. 3820 210 M.7 LA.3

~~c) Each diesel generator shall be started for this test by using one of the following signals:~~ A.8

~~1) Manual.~~

~~2) Simulated loss of offsite power by itself.~~

~~3) Simulated loss of offsite power in conjunction with an ESF actuation test signal.~~

~~4) An ESF actuation test signal by itself.~~

add proposed Note 2 L.9

add proposed Notes 3 and 4 M.8

SR3.8.1.3 5. Verifying that after the diesel generator is synchronized, it is loaded to greater than or equal to 4400 KW for diesel generators EDG*1 and EDG*3 and greater than or equal to 2600 KW for diesel generator EDG*2 ~~in less than or equal to 90 seconds*~~ and operates with these loads for at least 60 minutes. 3960 kw and ≤ 2340 kw and ≤ L.10

~~6. Verifying the diesel generator is aligned to provide standby power to the associated emergency buses.~~ L.11

SR3.8.1.2* Note 1 / SR3.8.1.2 Note 2 / SR3.8.1.3 Note 1

All diesel generator starts for the purpose of this surveillance test may be preceded by an engine prelube period. Further, all surveillance tests, ~~with the exception of once per 184 days, may also be preceded by warmup procedures~~ and may also include gradual loading ~~as recommended by the manufacturer~~ so that the mechanical stress and wear on the diesel engine is minimized. L.10 B

A.1

ELECTRICAL POWER SYSTEMS

AC SOURCES

AC SOURCES - OPERATING

SURVEILLANCE REQUIREMENTS

4.8.1.1.2 (Continued) 24 L.D.1 L.13

e. At least once per 18 months,* during shutdown, by: A.9

1. Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service. LA.4 M.9

add proposed Note 2 to SR 3.8.1.7 LA.5

SR 3.8.1.7 2. Verifying the diesel generator capability to reject a load of greater than or equal to 1125 kW for diesel generator EDG*1, greater than or equal to 750 kW for diesel generator EDG*3, and greater than or equal to 2473 kW for diesel generator EDG*2 while maintaining its associated single largest post-accident load engine speed increase less than or equal to 75% of the difference between nominal speed and the overspeed trip setpoint or 15% of nominal, whichever is less. M.14 A.10

add proposed Note 2 to SR 3.8.1.8 M.9

SR 3.8.1.8 3. Verifying the diesel generator capability to reject a load of 4400 kW for diesel generators EDG*1 and EDG*3 and 2600 kW for diesel generator EDG*2 while operating within the power factor limit without tripping.** The generator voltage shall not exceed 4576 volts for EDG*1 and EDG*3, and 5824 volts for EDG*2 during and following the load rejection. 2 A.11

SR 3.8.1.9 4. Actual or Simulating a loss of offsite power by itself, and: L.14

a) For Divisions I and II:

1) Verifying deenergization of the emergency buses and load shedding from the emergency buses.

2) Verifying the diesel generator starts*** on the autostart signal, energizes the emergency buses with permanently connected loads within 23 seconds†, energizes the auto-connected (shutdown) loads through the load timers and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency buses shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test. L.15 13.20 LA.7 M.7 L.13 210

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* For any start of a diesel, the diesel must be operated with a load in accordance with the manufacturer's recommendations. L.13

** Momentary transients due to changing bus loads shall not invalidate the test. A.11

SR 3.8.1.9 Note 1 *** All diesel generator starts for the purpose of this surveillance test may be preceded by an engine prelube period. Further, all surveillance tests, with the exception of once per 184 days, may also be preceded by warmup procedures and may also include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized. A.12

SR 3.8.1.9 † From initiation of loss of offsite power.

A.1

ELECTRICAL POWER SYSTEMS

AC SOURCES

AC SOURCES - OPERATING

SURVEILLANCE REQUIREMENTS

4.8.1.1.2.e.4 (Continued)

SR 3.8.1.9 b) For Division III:

1) Verifying deenergization of the emergency bus.

2) Verifying the diesel generator starts* on the autostart signal, energizes the emergency bus with the permanently connected loads within 13 seconds** and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency bus shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test. L.15 13.20 B M.7 210 L.14

SR 3.8.1.10 5. Verifying that on an ECCS actuation actual or test signal, without loss of offsite power: M.7

a) That diesel generators EDG*1 and EDG*3 start* on the autostart signal and operate on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 1.2 Hz within 10 seconds and 4160 ± 416 volts and 60 ± 1.2 Hz within 13 seconds after the autostart signal; the steady state generator voltage and frequency shall be maintained within these limits during this test. 1.2 M.10 L.8 210 M.7 L.8 LA.3 add proposed SR3.8.1.10 / 2 cycle M.11

b) That diesel generator EDG*2 starts* on the autostart signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 1.2 Hz within 15 seconds after the autostart signal; the steady state generator voltage and frequency shall be maintained within these limits during this test. 210 M.7 LA.3

SR3.8.1.9 Note 1 and SR3.8.1.10 Note 1

* All diesel generator starts for the purpose of this surveillance test may be preceded by an engine prelube period. Furthermore all surveillance tests, with the exception of once per 184 days, may also be preceded by warmup procedures and may also include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized. A.12

SR3.8.1.9 ** From initiation of loss of offsite power.

M.10 The generator voltage and frequency shall be ≥3820 V and ≥58.0 Hz in 10 seconds

A.1

Specification 3.8.1

ELECTRICAL POWER SYSTEMS

AC SOURCES

AC SOURCES - OPERATING

SURVEILLANCE REQUIREMENTS

4.8.1.1.2.e (Continued)

SR 3.8.1.16 12. Verifying that the automatic load timer relays are OPERABLE with the interval between each load block within ± 10% of its design interval for diesel generators EDG*1 and EDG*3.

L.18 add proposed Note 2

13. Verifying that the following diesel generator lockout features prevent diesel generator starting only when required: L.17

a) For Divisions I and II, turning gear engaged and emergency stop. LD.1

b) For Division III, engine in the maintenance mode and diesel generator lockout. L.7

SR 3.8.1.13 f. At least once per 18 months (24) verify each diesel generator starts and accelerates to at least 600 RPM within 10 seconds for EDG*1 and EDG*3, and 870 RPM within 10 seconds for EDG*2. The generator voltage and frequency for EDG*1 and EDG*3 shall be 4160 ± 416 volts and 60 ± 3.0 Hz within 10 seconds and 4160 ± 416 volts and 60 ± 1.2 Hz within 13 seconds after the start signal. The generator voltage and frequency for EDG*2 shall be 4160 ± 416 volts and 60 ± 1.2 Hz within 15 seconds after the start signal. This test shall be performed within 5 minutes of shutting down the diesel generator after the diesel generator has operated for at least 2 hours at 4400 kW or more for EDG*1 and EDG*3 and 2600 kW or more for EDG*2. For any start of a diesel, the diesel must be loaded in accordance with manufacturer's recommendations. Momentary transients due to changing bus loads shall not invalidate this test. L.8 M.7 L.7 M.7 M.7 L.9 L.13

L.8 ≥ 3820V in ≤ 10 seconds and LA.3

add proposed Note to SR 3.8.1.18

g. SR 3.8.1.18 At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all three diesel generators simultaneously, during shutdown, and verifying that all diesel generators EDG*1 and EDG*3 accelerate to at least 600 rpm and EDG*2 accelerates to at least 870 rpm in less than or equal to 10 seconds. L.18 L.19 L.20 58.8 Hz

add proposed voltage limits M.13 L.7

h. At least once per 10 years by:

1. Draining each fuel oil storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite solution, and A.3 moved to LCO 3.8.3

2. Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code in accordance with ASME Code Section XI Article IWD-5000. B

4.8.1.1.3 All diesel generator failures, valid or non-valid, shall be reported to the Commission pursuant to Specification 6.9.2, within 30 days. Reports of diesel generator failures shall include the information recommended in Position C.3.b of RG 1.108, Revision 1, August 1977. If the number of failures in the last 100 valid tests, on a per nuclear unit basis, is greater than or equal to 7, the report shall be supplemented to include the additional information recommended in Position C.3.b of RG 1.108, Revision 1, August 1977. L.21

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 The details relating to the required day tank level in CTS 3.8.1.1.b.1 have been moved to proposed SR 3.8.1.4. No technical changes are being made; therefore, this change is considered administrative in nature.

A.3 The technical content of CTS 3.8.1.1.b.2, 3.8.1.1 Actions j, k, and l, 4.8.1.1.2.a.2, 4.8.1.1.2.a.7, 4.8.1.1.2.a.8, 4.8.1.1.2.b.2, 4.8.1.1.2.c, and 4.8.1.1.2.h is being moved to ITS 3.8.3. This is in accordance with the format of the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. Any technical changes to these requirements are addressed in the Discussion of Changes for ITS: 3.8.3.

A.4 The ITS Applicability includes a Note which, in the event the HPCS System is inoperable, allows the Division 3 DG to not be required to be OPERABLE. The effect is to continue to allow the ACTIONS to be applied to other AC sources inoperabilities, without the complexity of also having the AC Sources Specification address concurrent HPCS DG inoperability. The format and implementation rules for the ITS would dictate several additional ACTIONS or a separate LCO for the Division 3 DG, to address each HPCS DG inoperability in combination with each of the other required AC sources in order to provide ACTIONS similar to those in the current NMP2 TS. The actual implementation of the Applicability Note is consistent with the intent of CTS 3.8.1.1, which separates Actions for Divisions 1 and 2 DGs from Actions for Division 3 DG. Therefore, this addition is an administrative change. (B) (B) (B) (B)

A.5 AC Sources in CTS 3.8.1.1 (ITS 3.8.1) are considered a support system to the Distribution System in CTS 3.8.3.1 (ITS 3.8.8). In the event AC Sources are inoperable such that a distribution subsystem were inoperable, ITS LCO 3.0.6 would allow taking only the AC Sources ACTIONS; taking exception to complying with the AC Distribution System ACTIONS. Since the AC Sources ACTIONS may not be sufficiently conservative in this event (an entire division may be without power), specific direction to take appropriate ACTIONS for the Distribution System is added (ITS 3.8.1, Note to ACTION D) when there is no power for a division. This format and construction implements the existing treatment of this condition within the framework of the NMP2 Improved Technical Specification methods.

ADMINISTRATIVE (continued)

A.6 CTS 3.8.1.1 Action d requires the HPCS System to be declared inoperable and to take the Action required by Specification 3.5.1 when the Division 3 DG is inoperable. CTS 3.8.1.1 Action e requires that when a redundant system, subsystem, train, component, or device is inoperable, the redundant systems, subsystems, trains, components, and devices served by the inoperable DG must be declared inoperable and the Actions required by the associated Specification(s) for both inoperable divisional systems, subsystems, trains, components, and devices taken. The format of the ITS does not include providing "cross references". The individual Specifications adequately prescribe the Required Actions for inoperable systems, subsystems, trains, components, and devices without such references. Therefore, the current NMP2 TS references to "take the ACTION required by..." in CTS 3.8.1.1 Actions d and e serve no functional purpose, and their deletion is an administrative presentation preference.

A.7 The format of the ITS allows multiple Conditions to be simultaneously entered. With three or more AC sources inoperable (e.g., two offsite circuits and one DG), ACTIONS would be taken in accordance with ITS 3.8.1, and ITS LCO 3.0.3 entry conditions would not be met. However, CTS 3.8.1.1 does not provide Actions for these conditions. Therefore, a CTS 3.0.3 entry would be required. To preserve the existing intent for CTS 3.0.3 entry, ITS 3.8.1 ACTION G is added to direct entry into ITS LCO 3.0.3.

A.8 CTS 4.8.1.1.2.a.4.c) requires the DG to be started for the normal 31 day Surveillance test using the manual signal, simulated loss of offsite power signal, ESF actuation test signal, or simulated loss of offsite power signal in conjunction with an ESF actuation test signal. The ITS does not include this requirement. These signals are the only signals that can be used to start the DGs and are described in the USAR. Therefore, there is no reason to describe these four signals in the ITS, since there are no other signals available; no other signals other than these can be used. As such, this deletion is considered administrative.

A.9 The CTS 4.8.1.1.2.e existing limitation on 18-month Surveillances to perform them "during shutdown" is more specifically presented in the proposed Surveillances. Each proposed SR contains a specific Note limiting the performance in certain MODES. While these limitations vary from SR to SR, each is consistent with the BWR Standard Technical Specifications, NUREG-1434, Rev. 1 presentation (or bracketed option allowed based on plant specific justification) which defines the intent of "during shutdown" for each SR, and with the guidance of Generic Letter 91-04. Additionally, the ITS Note clearly presents the allowance of the current practice of taking credit for unplanned events, provided the necessary data is obtained.

ADMINISTRATIVE (continued)

A.10 CTS 4.8.1.1.2.e.2 requires the DG to reject the single largest load while maintaining the engine speed increase ≤ 75% of the difference between nominal speed and the overspeed trip setpoint or ≤ 15% of the nominal speed, whichever is less. These two possible values for the overspeed trip point are fixed by the design of the DG unit. The appropriate value (i.e., the most limiting, which is 64.5 Hz for Division 1 and 2 DGs and 66.75 Hz for Division 3 DG) is presented in proposed SR 3.8.1.7. This presentation eliminates the basis for the accepted value from the Technical Specifications, moving it to the Bases. Since there is no difference in the requirement, this is an editorial presentation preference only.

A.11 CTS 4.8.1.1.2.e.3 footnote ** allows that, during the full load reject test, momentary transients of the bus load will not invalidate the test. This allowance provides for minor deviations from the singular fixed load value of the surveillance. Proposed SR 3.8.1.8 has provided for this deviation by requiring the load to be equal to or greater than the rated load capacity. Therefore, the deletion of this footnote is considered to be an administrative change.

A.12 CTS 4.8.1.1.2.e.4.a) footnote ***, CTS 4.8.1.1.2.e.4.b) footnote *, CTS 4.8.1.1.2.e.5 footnote *, and CTS 4.8.1.1.2.e.6 footnote * allow certain tests to be preceded by DG warmup procedures and to allows the DG to be gradually loaded to minimize mechanical stress and wear. These allowances are not included in the ITS. CTS 4.8.1.1.2.e.4.a) and b) and CTS 4.8.1.1.2.e.6 verify proper DG response when initiated by a start signal that includes a loss of power signal. These tests require the DG to be automatically loaded. Therefore, to meet the acceptance criteria of the tests, the allowances of the associated footnotes cannot be used. CTS 4.8.1.1.2.e.5 verifies proper DG response when initiated by an ECCS actuation signal only. This test does not include a verification of DG loading; only a DG start and unloaded run is required. Therefore, the associated footnote does not provide any needed allowance. As such, the deletion of these footnotes is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.8 (cont'd) SR be immediately preceded by a successful performance of SR 3.8.1.2 (the DG start Surveillance). This will ensure the DG load carrying capability is tested subsequent to a successful DG start test. While these Notes clearly represent current NMP2 practice, they are more restrictive than the CTS since the SR could currently be performed without these restrictions.

M.9 Limitations on the operating power factor are added to CTS 4.8.1.1.2.e.2, the single load rejection test (proposed Note 2 to SR 3.8.1.7), CTS 4.8.1.1.2.e.3, the full load rejection test (proposed SR 3.8.1.8, including Note 2), and CTS 4.8.1.1.2.e.8, the 24-hour run Surveillance (proposed SR 3.8.1.12, including Note 3). These limitations ensure the DG is conservatively tested at as close to accident conditions as reasonable, provided the power factor can be attained. The actual power factor values have been added to the Bases. A Note has been also added to CTS 4.8.1.1.2.e.8 (proposed SR 3.8.1.12 Note 1) to ensure a momentary transient that results in the power factor not being met does not invalidate the 24 hour run. These changes are more restrictive on plant operation.

M.10 CTS 4.8.1.1.2.e.5.a) requires the Division 1 and 2 DGs accelerate to 57 Hz (60 Hz - 3.0 Hz) within 10 seconds. CTS 4.8.1.1.2.e.5.b) does not provide any minimum voltage or frequency the Division 3 DG must meet within the 10 second DG start time assumed in the accident analysis. Proposed SR 3.8.1.10 requires the minimum frequency for Division 1 and 2 DGs to be 58.8 Hz and requires the minimum voltage and frequency for the Division 3 DG to be 3820 V and 58.0 Hz, respectively. The frequency for Division 1 and 2 DGs is consistent with Regulatory Guide 1.9, Rev. 3 and with the steady state frequency limit the DGs are currently required to maintain. The frequency for Division 3 DG is consistent with CTS 4.8.1.1.2.a.4.b). The voltage ensures that components powered by the associated bus will have sufficient voltage to perform their required function. These are additional restrictions on plant operation.

M.11 Two new requirements have been added to CTS 4.8.1.1.2.e.5.a). SR 3.8.1.10.d and SR 3.8.1.10.e ensure that Division 1 and 2 permanently connected loads remain energized from the offsite power system and that Division 1 and 2 emergency loads are autoconnected to the offsite power system. This is required since separate load timers are used to autoconnect some of the Division 1 and 2 emergency loads to the offsite power system, and if the proper load timer does not operate, an offsite circuit could be impacted. This is an additional restriction on plant operation. 1 B

TECHNICAL CHANGES - LESS RESTRICTIVE

L.9 (cont'd) In addition, a Note has been added to CTS 4.8.1.1.2.a.5 (proposed SR 3.8.1.3 Note 2) stating that momentary transients outside the load range do not invalidate the Surveillance. This is to account for momentarily changing bus loads and precludes re-performance of the Surveillance solely due to the load being outside the load range as a result of a momentary transient. Demonstration of the load carrying capability and the ensurance of the DG at proper operating temperatures continue to be adequately tested because momentary transients are of short duration compared to the Surveillance test duration. This Note is also consistent with similar allowances of CTS 4.8.1.1.2.e.8 and 4.8.1.1.2.f.

L.10 The CTS 4.8.1.1.2.a.5 90-second limitation on the time to reach full DG load from a manual synchronization, required to be performed every 184 days as stated in footnote * to CTS 4.8.1.1.2.a.5, as well as the restriction to warming up the DG prior to loading, are proposed to be deleted. DG warmup and loading should be done in accordance with manufacturer's recommendations to minimize wear on the engine. Additionally, placing a time limitation on the operator to accomplish this loading results in an increased potential for error and subsequent unavailability of the DG. The starting, loading, subsequent full load operation, and automatic start and loading testing required by other ITS 3.8.1 Surveillance Requirements is adequate to confirm the DG's capability without the warmup restriction and 90-second loading requirement. 1B 1B

L.11 CTS 4.8.1.1.2.a.6 requires verification that each DG is aligned to provide standby power to the associated emergency buses. The requirements of ITS 3.8.1, which require the DGs to be OPERABLE, and the associated Surveillance Requirements for the DGs are adequate to ensure the DGs are maintained OPERABLE. In addition, the definition of OPERABILITY and procedural controls on DG standby alignment are sufficient to ensure the DG remains aligned to provide standby power. In general, this type of requirement is addressed by plant specific processes which continuously monitor plant conditions to ensure that changes in the status of plant equipment that require entry into ACTIONS (as a result of failure to maintain equipment OPERABLE) are identified in a timely manner. This verification is an implicit part of using Technical Specifications and determining the appropriate Conditions to enter and Actions to take in the event of inoperability of Technical Specification equipment. In addition, plant and equipment status is continuously monitored by control room personnel. The results of this monitoring process are documented in records/logs maintained by control room personnel, as required. The continuous monitoring process includes re-evaluating the status of compliance with Technical Specification requirements when Technical Specification equipment becomes inoperable using the control room

TECHNICAL CHANGES - LESS RESTRICTIVE

L.11 (cont'd) records/logs as aids. Therefore, the explicit requirement to periodically verify that each DG is aligned to provide standby power to the associated emergency buses is considered to be unnecessary for ensuring compliance with the applicable Technical Specification OPERABILITY requirements and is to be removed from the Technical Specifications.

L.12 CTS 4.8.1.1.2.b.1 requires checking for and removing accumulated water from the DG day tanks every 31 days and "after each occasion when the diesel is operated for more than 1 hour." Proposed SR 3.8.1.5 only requires the check every 31 days; the frequency of "after each occasion when the diesel is operated for more than 1 hour" has been deleted. Water condensation within the fuel oil tanks is a time dependent process, not a process dependent on the transfer of fuel oil during DG operation. Furthermore, the fuel oil storage tank is similarly maintained free of accumulated water (CTS 4.8.1.1.2.b.2 and proposed SR 3.8.3.5). In the event the DG is not operated except for the nominal monthly OPERABILITY tests (which is the expectation), no increased Frequency is applied.

L.13 CTS 4.8.1.1.2.e footnote * and CTS 4.8.1.1.2.f require the diesel to be operated with a load in accordance with the manufacturer's recommendations any time the diesel is started to perform the Surveillances of CTS 4.8.1.1.2.e and CTS 4.8.1.1.2.f. The ITS does not include this requirement. This requirement is essentially a preventative maintenance type of requirement. The failure to perform this requirement does not necessarily result in an inoperable DG. This requirement is oriented toward long term DG OPERABILITY and does not have an immediate impact on DG OPERABILITY. In cases where the DG is started and not loaded, plant practice is to restart the DG and run it loaded for the manufacturer recommended time. In these cases, the DG normally starts properly; i.e., it is not found inoperable just because it was not loaded after a start. In addition, Generic Letter 83-28 required that utilities ensure that vendor recommended practices in vendor manuals be properly implemented in plant procedures. NMP2 has complied with this Generic Letter (specifically as it relates to the DGs). Therefore, this requirement is not necessary to be maintained in the ITS.

L.14 The phrase "actual or", in reference to the loss of offsite power signal or the ECCS actuation signal, as applicable, has been added to CTS 4.8.1.1.2.e.4, 4.8.1.1.2.e.5, 4.8.1.1.2.e.6, 4.8.1.1.2.e.7, and 4.8.1.1.2.e.11 (proposed SRs 3.8.1.9, 3.8.1.10, 3.8.1.17, 3.8.1.11, and 3.8.1.15, respectively) for verifying the proper response of the DG. This allows satisfactory loss of offsite power or ECCS actuations for other than Surveillance purposes to be used to fulfill the Surveillance Requirement. OPERABILITY is adequately

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L.14 (cont'd) demonstrated in either case since the DG cannot discriminate between "actual" or "simulated" signals.

L.15 CTS 4.8.1.1.2.e.4.a)2) and 4.8.1.1.2.e.4.b)2) require the DGs to start and energize the emergency buses within 13 seconds of a loss of offsite power signal. Proposed SR 3.8.1.9 will allow the DGs to start and energize the emergency buses within 13.20 seconds. This proposed time is the summation of the current DG start time of 10 seconds (from various CTS 4.8.1.1 Surveillances) and the DG loss of voltage time delay Allowable Value (from CTS Table 3.3.3-2 Trip Functions D.1 and E.1, as modified by an "L" Discussion of Change in ITS 3.3.8.1). This is also the time assumed in the accident analysis for the DG to start when only a loss of voltage occurs. The current time in CTS 4.8.1.1.2.e.4.a)2) and b)2) is essentially the allowed DG start and energization time rounded to the nearest whole second. Therefore, this change is effectively making the DG start and energization time of CTS 4.8.1.1.2.e.4.a)2 and b)2) consistent with the current allowed times in other portions of the CTS (as modified by an appropriate Discussion of Change in ITS 3.3.8.1).

L.16 The manner in which the DG is started for CTS 4.8.1.1.2.e.8 (i.e., that the DG must be within the proper voltage and frequency within a certain time limit after the start signal) has not been included in proposed SR 3.8.1.12. While this test can be performed only after a fast start, the manner in which the DG is started does not affect the test. In addition, maintaining voltage and frequency (as required by CTS 4.8.1.1.2.e.8) is routine for this test to ensure the loads are maintained within the necessary limits, and does not need to be specified. Other Surveillance Requirements being maintained in the ITS (e.g., CTS 4.8.1.1.2.a.4, proposed SR 3.8.1.2) continue to require verifying the DG start time and voltage and frequency limits. If these limits are found not to be met during the performance of proposed SR 3.8.1.12, then the DG would be declared inoperable. As a result, these requirements are not necessary to be included in the Technical Specifications to ensure the diesel generators are maintained OPERABLE.

L.17 CTS 4.8.1.1.2.e.13, which verifies the DG lockout features prevent DG starting only when required, is proposed to be deleted. If a DG lockout feature prevents the DG from operating during an accident, this will still be identified during the LOCA, LOOP, and LOCA/LOOP DG Surveillances (proposed SRs 3.8.1.9, 3.8.1.10, and 3.8.1.17), which are currently performed at the same periodicity as this Surveillance. It will also be identified during the normal 31 day test, proposed SR 3.8.1.2. Failure of a lockout feature to properly lockout a DG is not a concern as it relates to meeting accident analysis

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L.17 (cont'd) assumptions, since the DG would already be assumed not to be functioning (the lockout features are used to prevent the DG from starting on an accident signal). Therefore, removal of this Surveillance from the Technical Specifications will have no effect on DG OPERABILITY.

L.18 A Note to CTS 4.8.1.1.2.f and 4.8.1.1.2.g (proposed SR 3.8.1.13 and SR 3.8.1.18) has been added to allow a prelube prior to starting the DG. DG starts without prior engine prelube create unnecessary engine wear, thereby reducing overall reliability. The engine prelube does not result in an enhanced start performance that could mask the engine's inability to start in accident conditions without a prelube. This Note is also consistent with the allowance provided in all other DG starts required by the CTS.

L.19 Explicit post maintenance Surveillance Requirements as required by CTS 4.8.1.1.2.g (i.e., after any modifications which could affect DG interdependence) have been deleted. Any time the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. After restoration of a component that caused a required SR to be failed, ITS SR 3.0.1 requires the appropriate SRs (in this case, SR 3.8.1.18) to be performed to demonstrate the OPERABILITY of the affected components. Therefore, explicit post maintenance Surveillance Requirements are not repaired and have been deleted from the Technical Specifications.

L.20 The requirement to perform CTS 4.8.1.1.2.g during shutdown has not been included in proposed SR 3.8.1.18. The proposed Surveillance (to simultaneously start all three DGs) does not include the restriction on plant conditions. The Surveillance can be adequately tested in the operating conditions without jeopardizing safe plant operations, since the Surveillance does not require the DGs to be connected to their respective buses; the Surveillance only requires a start of the DGs. The control of plant conditions appropriate to perform the Surveillance is an issue for procedures and scheduling, and has been determined by the NRC Staff to be unnecessary as a Technical Specification restriction. As indicated in Generic Letter 91-04, allowing this control is consistent with the vast majority of other Technical Specification Surveillances that do not dictate plant conditions for the Surveillance.

L.21 CTS 4.8.1.1.3, which requires that all DG failures be reported to the NRC in a special report pursuant to CTS 6.9.2, is proposed to be deleted. This requirement is proposed to be removed from Technical Specifications in accordance with the guidance of Generic Letter 94-01. GL 94-01 allows DG

TECHNICAL CHANGES - LESS RESTRICTIVE

L.21 (cont'd) failure reporting requirements to be removed, but licensees must continue to comply with reporting requirements of 10 CFR 50.72 and 50.73, which may require notifying and reporting DG failures to the NRC. Also, this change does not impact the safe operation of the plant because the report is submitted after the DG failure has occurred and does not require NRC approval. Therefore, this requirement is being removed from the Technical Specifications consistent with the guidance of GL 94-01.

L.22 If an offsite circuit is inoperable only due to its inability to provide power the Division 3 electrical power distribution subsystem, CTS 3.8.1.1 Action a would require a unit shutdown if the offsite circuit is not restored to OPERABLE status within 72 hours. ITS 3.8.1 provides an Applicability Note which, in the event the HPCS System is inoperable, allows the Division 3 offsite circuits to not be required to be OPERABLE. Thus, at the end of the current 72 hour restoration time, the ITS Note would allow HPCS to be declared inoperable, and the ACTIONS in ITS 3.5.1 would be taken for an inoperable HPCS System. The ACTIONS in ITS 3.5.1 allow 14 days to restore HPCS to OPERABLE status. The overall effect of this change is to allow an additional 14 days to restore the circuit to OPERABLE status, since that is the only way to restore the HPCS System to OPERABLE status under this condition. The 14 day allowance is consistent with the allowance already provided in CTS 3.8.1.1 Action d for when the HPCS DG is inoperable. The two conditions (i.e., loss of the offsite circuit and loss of DG) are essentially the same; the HPCS System can still perform its intended function, however, it only has one source of power. In addition, the CTS 3.5.1 currently allows the HPCS System to be inoperable for up to 14 days for other reasons that will preclude it from performing its intended function. Since the NRC has previously approved the 14 day allowance for when the HPCS DG is inoperable, as well as when the HPCS System is inoperable for other reasons, this change is considered acceptable. In addition, this 14 day time for when HPCS is inoperable is also consistent with the Memorandum from R. L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975. B

TECHNICAL CHANGES - MORE RESTRICTIVE

M.2 (cont'd) more systems, subsystems, or components required to be OPERABLE. This added restriction enforces a level of Technical Specification control which currently is enforced only via administrative procedures.

M.3 CTS 3.8.1.2 Action a requires that, when in MODE 5 with the water level less than 22 feet above the RPV flange, action is to be initiated to restore the required AC power sources to OPERABLE status. ITS 3.8.2 Required Actions A.2.4 and B.4 implement a requirement to initiate action to restore the required power sources to OPERABLE status in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment. This will ensure actions are taken at all times when an AC Source is inoperable, not just in MODE 5 with water level less than 22 feet above the RPV flange. Therefore, this change is an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The CTS 3.8.1.2.b.3 detail relating to system design and OPERABILITY (i.e., that each DG has two fuel oil transfer pumps) is proposed to be relocated to the Bases. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. The design details are not necessary to be included in the Technical Specifications to ensure the OPERABILITY of the DGs since OPERABILITY requirements are adequately addressed in ITS 3.8.2, "AC Sources — Shutdown." 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.

LA.2 CTS 3.8.1.2 Action a requires supervision of crane operations over the spent fuel storage pool when an AC Source is inoperable. Crane operation is not directly affected by the loss of safety related power sources. Therefore, CTS 3.8.1.2 Action a associated with crane operation following a loss of AC power sources is proposed to be relocated to the USAR. Movement of loads other than fuel assemblies is administratively controlled based on heavy loads analyses. The bounding design basis fuel handling accident assumes an irradiated fuel assembly is dropped onto an array of irradiated fuel assemblies seated within the RPV. The movement of other loads over irradiated fuel assemblies is administratively controlled based on available analysis for the individual load. In addition, NMP2 is consistent with the requirements of

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LA.2 (cont'd) Generic Letter 80-113 and NUREG-0612, as documented in the USAR, Appendix 9C. Therefore, the relocated requirement is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the USAR will be controlled by the provisions of 10 CFR 50.59. B

"Specific"

L.1 CTS 3.8.1.2.b requires the Division 3 DG to be OPERABLE when the HPCS System is required to be OPERABLE. ITS LCO 3.8.2.c will allow a qualified offsite circuit, other than the circuit required to provide power to Division 1 and 2, to substitute for the DG. The proposed allowance will continue to ensure adequate power is available to supply the HPCS System during a shutdown condition. This circuit must be separate from that required to power Division 1 and 2, thus a single failure of one offsite circuit will not result in loss of all offsite power. In addition, the reliability of the offsite circuit is generally greater than the DG.

L.2 Many of the currently required Surveillances specified in CTS 4.8.1.2 involve tests that would require the DG to be paralleled to offsite power. This condition (the only required DG and the only required offsite circuit connected) presents a significant risk of a single fault resulting in a station blackout. The NRC has previously recognized this in the exception stated in CTS 4.8.1.2 and provided surveillance exceptions to avoid this condition. In an effort to consistently address this concern and to avoid potential conflicting Technical Specifications, the Surveillances that would require the DG to be connected to the offsite source are excepted from performance requirements. The exception does not take exception to the requirement for the DG to be capable of performing the particular function; just to the requirement to demonstrate it while that source of power is being relied on to support meeting the LCO. The exception is being presented in the form of a Note to proposed SR 3.8.2.1.

L.3 CTS 4.8.1.1.3, which requires that all DG failures be reported to the NRC in a special report pursuant to CTS 6.9.1, is proposed to be deleted. This requirement is being removed from Technical Specifications in accordance with the guidance of Generic Letter 94-01. GL 94-01 allows DG failure reporting requirements to be removed, but licensees must continue to comply with reporting requirements of 10 CFR 50.72 and 50.73, which may require notifying and reporting DG failures to the NRC. Also, this change does not impact the safe operation of the plant because the report is submitted after the DG failure has occurred and does not require NRC approval. Therefore, this

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L.3 (cont'd) requirement is being removed from the Technical Specifications consistent with the guidance of GL 94-01.

L.4 CTS 4.8.1.2, which provides the Surveillance Requirements for the AC Sources while in Modes 4 and 5 and during handling of irradiated fuel in the secondary containment, requires the Surveillances of CTS 4.8.1.1.2 to be performed. Two of the Surveillances of CTS 4.8.1.1.2 are the DG start on an ECCS initiation signal and the DG start and load on an ECCS initiation signal concurrent with a loss of offsite power signal. Proposed Note 2 to SR 3.8.2.1 will exempt these two Surveillances when the associated ECCS subsystem(s) are not required to be Operable. The CTS and ITS do not require the ECCS subsystem(s) to be Operable in Mode 5 when the spent fuel storage pool gates are removed and water level is ≥ 22 ft 3 inches over the top of the reactor pressure vessel flange. The CTS and ITS also do not require the ECCS subsystem(s) to be Operable when defueled. The DGs are required to support the equipment powered from the emergency buses. However, when the ECCS subsystem(s) are not required to be Operable, then there is no reason to require the DGs to autostart on an ECCS initiation signal. In addition, the ECCS initiation signal is only an anticipatory start signal; the DGs are only needed during a LOCA if a loss of offsite power occurs concurrently. The DGs are also required to autostart if a loss of offsite power occurs. The requirement to autostart the required DG(s) on a loss of offsite power signal is being maintained in the ITS (proposed SR 3.8.1.9). Thus, when in these conditions (associated ECCS subsystem(s) not required to be Operable), there is no reason to require the DGs to be capable of automatically starting on an ECCS actuation signal (either by itself or concurrent with a loss of offsite power signal).

A.1

Specification 3.8.3

4.8.1.1.2.e (Continued)

12. Verifying that the automatic load timer relays are OPERABLE with the interval between each load block within ± 10% of its design interval for diesel generators EDG*1 and EDG*3.

13. Verifying that the following diesel generator lockout features prevent diesel generator starting only when required:

a) For Divisions I and II, turning gear engaged and emergency stop.

b) For Division III, engine in the maintenance mode and diesel generator lockout.

f. At least once per 18 months verify each diesel generator starts and accelerates to at least 600 RPM within 10 seconds for EDG*1 and EDG*3, and 870 RPM within 10 seconds for EDG*2. The generator voltage and frequency for EDG*1 and EDG*3 shall be 4160 ± 416 volts and 60 ± 3.0 Hz within 10 seconds and 4160 ± 416 volts and 60 ± 1.2 Hz within 13 seconds after the start signal. The generator voltage and frequency for EDG*2 shall be 4160 ± 416 volts and 60 ± 1.2 Hz within 15 seconds after the start signal. This test shall be performed within 5 minutes of shutting down the diesel generator after the diesel generator has operated for at least 2 hours at 4400 kW or more for EDG*1 and EDG*3 and 2600 kW or more for EDG*2. For any start of a diesel, the diesel must be loaded in accordance with manufacturer's recommendations. Momentary transients due to changing bus loads shall not invalidate this test.

g. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all three diesel generators simultaneously, during shutdown, and verifying that all diesel generators EDG*1 and EDG*3 accelerate to at least 600 rpm and EDG*2 accelerates to at least 870 rpm in less than or equal to 10 seconds.

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

1. ~~Draining each fuel oil storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite solution, and~~

2. ~~Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code in accordance with ASME Code Section XI Article IWD-5000.~~

L.4

B

4.8.1.1.3 All diesel generator failures, valid or non-valid, shall be reported to the Commission pursuant to Specification 6.9.2, within 30 days. Reports of diesel generator failures shall include the information recommended in Position C.3.b of RG 1.108, Revision 1, August 1977. If the number of failures in the last 100 valid tests, on a per nuclear unit basis, is greater than or equal to 7, the report shall be supplemented to include the additional information recommended in Position C.3.b of RG 1.108, Revision 1, August 1977.

B

See Discussion of Changes for ITS: 3.8.1, in this Section

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) levels of degradation in air start receiver pressure are justified to extend the allowances for restoration (presented as ITS 3.8.3 ACTIONS E and F and ACTIONS Note). During the extended restoration periods for this parameter, the DG would still be capable of performing its intended function. ITS 3.8.3 ACTION E, which is entered on a per DG basis (as allowed by the ACTIONS NOTE), allows 48 hours to restore starting air pressure prior to declaring the DG inoperable, provided a one start capacity remains. ITS 3.8.3 ACTION F is provided to declare the DG inoperable if the previous ACTION is not met. During the proposed extended periods for restoration of this parameter, the DG would still be capable of performing its intended function.

L.2 The Surveillance Frequency of CTS 4.8.1.1.2.a has been changed from "frequency specified in Table 4.8.1.1.2-1" (the DG test schedule table) to "31 days." This is because DG failures that result in a more frequent DG test frequency have no impact on the fuel oil storage tank level or the starting air systems ability to perform its intended function. Therefore the 31 day frequency is acceptable.

L.3 CTS 4.8.1.1.2.a requires the fuel oil storage tank level and the starting air pressure of each DG to be verified on a STAGGERED TEST BASIS. Proposed SR 3.8.3.1 and SR 3.8.3.4 do not include this requirement. The intent of a requirement for staggered testing is to increase reliability of the component/system being tested. A number of reviews/evaluations have been performed which have demonstrated that staggered testing has negligible impact on component reliability. As a result, it has been determined that staggered testing 1) is operationally difficult, 2) has negligible impact on component reliability, 3) is not as significant as initially thought, and 4) has no impact on failure frequency. Therefore, the staggered testing requirements for diesel fuel oil level and starting air pressure verification have been deleted.

L.4 The 10 year Surveillances of CTS 4.8.1.1.2.h to drain, remove sediment, and clean each fuel oil tank, and to perform a pressure test on the DG fuel oil system piping are proposed to be deleted. These Surveillances are preventive maintenance type requirements. Sediment in the tank, or failure to perform these Surveillances, do not necessarily result in an inoperable storage tank. Performance of proposed SR 3.8.3.3 (fuel oil testing) and the limits of the Diesel Fuel Oil Testing Program help ensure tank sediment is minimized. Performance of proposed SR 3.8.3.1 (fuel oil volume verification) once per 31 days ensures that any degradation of the tank wall surface that results in a fuel oil volume reduction is detected and corrected in a timely manner. The pressure test of the fuel oil system is already covered by ASME Code Section XI Article IWD-5000. This is currently implemented in the NMP2

TECHNICAL CHANGES - LESS RESTRICTIVE

L.4 (cont'd) Pressure Testing Program procedures. In addition, another government agency provides regulations for the maintenance of below ground fuel oil tanks. As a result, adequate controls exist such that these requirements are unnecessary to maintain in the Technical Specifications. 1 B

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A requirement to ensure that the battery cell to cell and terminal connections are coated with anti-corrosion material has been added to CTS 4.8.2.1.c.2 (proposed SR 3.8.4.4) consistent with IEEE-450 recommendations and the BWR Standard Technical Specifications, NUREG-1434, Rev. 1. This will help ensure that corrosion of the connections will not occur, thus assisting in maintaining resistance values within limits. This change is more restrictive on plant operation.

M.2 The 18 month Frequency for current Surveillance 4.8.2.1.f (proposed SR 3.8.4.8) is being changed to 12 months, consistent with the recommendations of IEEE-450-1995. This is an additional restriction on plant operations and will ensure the battery Operability is checked more frequently when degradation is detected or the battery has reached 85% of its service life, when the battery capacity is ≤ 100%.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 LCO 3.8.4 has been written to require the Division 1, 2 and 3 DC electrical power subsystems to be OPERABLE and the details relating to system OPERABILITY (what constitutes a DC Source division) in LCO 3.8.2.1 are proposed to be relocated to the Bases. The actual battery identification numbers are proposed to be relocated to the USAR. The Bases will include an adequate description of the batteries to properly identify them. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. As such, 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. Changes to the USAR are controlled by the provisions of 10 CFR 50.59. B B

LA.2 The detail for the basis of the resistance readings in footnote * of CTS 4.8.2.1.c.3 (IEEE 450-1980) is proposed to be relocated to the Bases. This detail is not necessary to ensure the OPERABILITY of the batteries. The requirements of proposed SR 3.8.4.5 are adequate to ensure the batteries are maintained OPERABLE and the resistance values are properly determined. 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)

L.5 An allowance to perform a modified performance discharge test in lieu of a performance discharge test has been added to CTS 4.8.2.1.e and f (proposed SR 3.8.4.8). The modified performance discharge test is a simulated duty cycle consisting of just two rates: the 1 minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test. Since the ampere-hours removed by a rated 1 minute discharge represent a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test.

L.6 CTS 4.8.2.1.f requires a battery performance discharge test every 18 months when the battery has reached 85% of its service life. A battery can be at 85% or greater of expected life, and still be within the required capacity to meet OPERABILITY requirements. In this event, a Frequency less restrictive than the 18 month Frequency is justified. Proposed SR 3.8.4.8 will now be required to be performed every 24 months when a battery has reached 85% of expected life with battery capacity ≥ 100% of manufacturer's rating. This new Frequency is also consistent with the BWR/6 STS, NUREG-1434, Rev. 1. B B

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The requirements for OPERABLE DC electrical power distribution subsystems are contained in ITS 3.8.9, "Distribution Systems—Shutdown." Thus, ITS LCO 3.8.5 has been written to require the DC electrical power distribution subsystem(s) required to support the electrical distribution subsystem(s) required by LCO 3.8.9 (see Discussion of Change M.1 above), and the details relating to system OPERABILITY in CTS 3.8.2.2 (what constitutes a required DC electrical power source) are proposed to be relocated to the Bases. The actual battery identification numbers are proposed to be relocated to the USAR. The Bases will include an adequate description of the batteries to properly identify them. The 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. Changes to the USAR are controlled by 10 CFR 50.59. B B

"Specific"

L.1 Three of the DC sources Surveillances required to be performed by CTS 4.8.2.2 (CTS 4.8.2.1.d, 4.8.2.1.e, and 4.8.2.1.f) involve tests that would cause the only required OPERABLE 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 NMP2 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 battery(s) 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.

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 (cont'd) required to support other Technical Specification equipment such as RCIC. Since the words of footnote † "The UPS shall be energized from their normal AC supply or their backup DC supply" does not specifically require the uninterruptible power supply (i.e., either the AC or the DC supply can be used to energize the UPS), this is considered more restrictive on plant operation. In addition, this requirement is being relocated to the Bases as described in Discussion of Change LA.1 below.

M.2 CTS 4.8.3.1.1 requires that each required power distribution system division be determined energized by verifying correct supply breaker alignment. Since CTS 3.8.3.1.a.1.c) and CTS 3.8.3.1.a.2.c) require the required distribution panels to be powered from the inverters, and footnote † requires the inverter to be energized from one of two sources, CTS 4.8.3.1.1 also covers the breaker alignment check of the inverter power supply. Proposed SR 3.8.7.1 includes not only the alignment check, but also requires verification of proper inverter voltage and frequency every 7 days. This will ensure the inverters can perform their assumed function; i.e., providing adequate voltage and frequency to the ECCS instrumentation. This requirement is considered more restrictive on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details of CTS 3.8.3.1, including footnote †, concerning the OPERABILITY requirements of the inverters are proposed to be relocated to the Bases. The actual inverter identification numbers are proposed to be relocated to the USAR. The Bases will include an adequate description of the inverters to properly identify them. The requirements of ITS 3.8.7 and SR 3.8.7.1 are adequate to ensure the Division 1 and 2 inverters are OPERABLE. For clarity, a name identifier, "emergency uninterruptible power supply (UPS) inverter" has been used since the equipment identification number has been relocated to the USAR. 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. Changes to the USAR are controlled by the provisions of 10 CFR 50.59. In addition, changes to the OPERABILITY requirements of the inverters is discussed in Discussion of Change M.1 above. B B B

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 CTS 3.8.3.1 Action a.1 allows 8 hours to reenergize an inoperable Division 1 or 2 120-volt AC distribution panel by its associated Division 1 or 2 inverter. The requirements to maintain these distribution panels energized is continued in ITS 3.8.8 (as required by proposed ITS 3.8.7 Required Action A.1 Note). If the 120-volt AC distribution panel is de-energized, ITS 3.8.8 ACTION B will require it to be re-energized within 8 hours, consistent with the time required in CTS 3.8.3.1 Action a.1. ITS LCO 3.8.7 only addresses the OPERABILITY of the Division 1 and 2 inverters and extends the restoration time from the current 8 hours to 24 hours (ITS 3.8.7 Required Action A.1). Experience has shown that a 24 hour restoration time for an inoperable inverter is appropriate, since the distribution panel, via an AC supply, is capable of being energized from a class 1E constant transformed source. During this additional 16 hours, the 120-volt AC distribution panel is energized and can perform its design function during a LOCA event, assuming no loss of offsite power. Therefore, this change is considered acceptable. B B

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 (cont'd) subsystem could again become inoperable, and the DC distribution restored OPERABLE. This could continue indefinitely. Therefore, to preclude this situation and place an appropriate restriction on any such unusual situation, the additional Completion Time of "16 hours from discovery of failure to meet LCO 3.8.8.a, b, or c" is proposed.

M.2 CTS 3.8.3.1 Action a.1 allows 8 hours to restore one inoperable AC subsystem and Action b.1 allows 2 hours to restore one inoperable DC subsystem. Certain combinations of inoperable AC and DC subsystems will result in a loss of safety function (e.g., an inoperable Division 1 AC subsystem in combination with an inoperable Division 2 DC subsystem). ITS 3.8.8 adds ACTION F, which requires entry into ITS 3.0.3 if the loss of two or more electrical power distribution subsystems results in a loss of safety function. ITS 3.8.8 Required Action F.1 preserves the intent of ITS 3.0.3 and reflects an additional restriction on plant operation.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details of CTS 3.8.3.1 relating to system design and OPERABILITY are proposed to be relocated to the Bases. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. The design details are not necessary to be included in the Technical Specifications to ensure the OPERABILITY of the Distribution Systems since OPERABILITY requirements are adequately addressed in ITS 3.8.8, "Distribution Systems — Operating." 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 Details of the methods for performing CTS 4.8.3.1.1 and 4.8.3.1.2 (on the switchgear, load centers, MCCs, and distribution panels) to verify the required Distribution Systems are OPERABLE are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the Distribution Systems. The requirements of ITS 3.8.8 and proposed SR 3.8.8.1 are adequate to ensure the required Distribution Systems are maintained OPERABLE. Since the methods to verify the Operability of the switchgear, load centers, MCCs, and distribution panels are different (the switchgear requires the voltage to be verified and the load centers, MCCs, and distribution panels require verification that no inoperability status indicator lights in the control room are lit that would indicate a loss of power to one or more of the

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.2 (cont'd) required load centers, MCCs, or distribution panels), the term power availability has been used to replace voltage and inoperability status indicator lights. 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. B

"Specific"

L.1 CTS 3.8.3.1 Action a.1 allows 8 hours to restore one inoperable AC subsystem and Action b.1 allows 2 hours to restore one inoperable DC subsystem. No time is provided if buses are inoperable in Division 1 and 2 AC subsystems concurrently or in Division 1 and 2 DC subsystems concurrently. Thus a CTS 3.0.3 entry is required. ITS 3.8.8 ACTIONS A, B, and C, allows one "or more" AC, 120 VAC uninterruptible, and DC electrical power distribution subsystems to be concurrently inoperable, without requiring an ITS 3.0.3 entry; either 8 hours or 2 hours (8 hours for AC and 2 hours for DC) will be allowed to restore the inoperabilities. However, ITS 3.8.8 ACTION F is also added to require that if two or more electrical power distribution subsystems are inoperable and result in a loss of function, then ITS 3.0.3 must be entered immediately. Thus if both Division 1 and Division 2 AC subsystems have similar buses inoperable, which result in a loss of function, ITS 3.8.8 ACTION F will ensure ITS 3.0.3 is entered, consistent with the CTS. This will ensure that the proper actions are taken if a loss of function occurs. Assuming a loss of function has not occurred, the addition of the words "or more" are acceptable since, during this time sufficient AC and DC buses are Operable to meet accident analysis (assuming no additional single failure). In addition, if an AC subsystem and a 120 VAC uninterruptible subsystem are inoperable, a total of 8 hours is provided in CTS 3.8.3.1 Action a.1 to restore both to OPERABLE status. ITS 3.8.8 ACTIONS A and B will allow each inoperability to be tracked separately, allowing a maximum of 16 hours to restore both subsystems (if the AC subsystem and 120 VAC uninterruptible subsystem inoperabilities are separated by 8 hours). However, ITS 3.8.8 ACTION F will also ensure that if this results in a loss of function, then ITS LCO 3.0.3 must be entered immediately. This additional time is acceptable since during this additional 8 hours, the unit can still meet accident analysis assumptions. Therefore, these changes will have negligible impact on plant safety. B

TECHNICAL CHANGES - MORE RESTRICTIVE (continued)

M.3 In lieu of declaring the HPCS System inoperable and taking the ACTIONS of the appropriate LCO as required by CTS 3.8.3.2 Actions a.2 and b.2, new Required Actions have been provided for when the Division 3 AC or DC distribution subsystem is inoperable, consistent with the current actions for inoperable Division 1 and Division 2 AC and DC distribution subsystems (CTS 3.8.3.2 Actions a.1 and b.1). ITS 3.8.9 Required Actions A.2.1, A.2.2 and A.2.3 require suspension of CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and OPDRVs. These Required Actions are more restrictive than currently required, since CTS 3.5.2 Action a only requires OPDRVs to be suspended (and it allows 4 hours to start this action), and ensure proper actions are taken to compensate for an inoperable HPCS System.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details of CTS 3.8.3.2 relating to system design and OPERABILITY are proposed to be relocated to the Bases. The details for system OPERABILITY are not necessary in the LCO. The definition of OPERABILITY suffices. The design details are not necessary to be included in the Technical Specifications to ensure the OPERABILITY of the Distribution Systems since OPERABILITY requirements are adequately addressed in ITS 3.8.9, "Distribution Systems—Shutdown." In addition, the source of power for the 120-volt AC distribution panels is not required since the current design provides only those sources specified (inverter or alternate supply). 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 Details of the methods for performing CTS 4.8.3.2.1 and 4.8.3.2.2 (on the switchgear, load centers, MCCs, and distribution panels) to verify the required Distribution Systems are OPERABLE are proposed to be relocated to the Bases. These details are not necessary to ensure the OPERABILITY of the Distribution Systems. The requirements of Specification 3.8.9 and SR 3.8.9.1 are adequate to ensure the required Distribution Systems are maintained OPERABLE. Since the methods to verify the Operability of switchgear, load centers, MCCs, and distribution panels are different (the switchgear requires the voltage to be verified and the load centers, MCCs, and distribution panels require verification that no inoperability status indicator lights in the control room are lit that would indicate a loss of power to one or more of the required load centers, MCCs, or distribution panels), the term power availability has

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.2 (cont'd) been used to replace voltage and inoperability status indicator lights. 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

<CTS>

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
<4.8.1.1.1> SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	7 days
<4.8.1.1.2.a.4> SR 3.8.1.2	-----NOTES----- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. ----- Verify each required DG starts from standby conditions and achieves: steady state voltage ≥ 3950 V and ≤ 4370 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	As specified in Table 3.8.1-1

TSTF-253

<4.8.1.1.2.a.4 "*" Footnote>

Pa. In ≤ 10 seconds

31 days

3950

for Division 1 and 2 DGs and ≥ 3820 V for Division 3 DG,

for Division 1 and 2 DGs and ≥ 58.0 Hz for Division 3 DG, and

Pb. Steady state voltage ≥ 3950 V and ≤ 4370 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.

(continued)

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
<4.8.1.1.2.e.4> SR 3.8.1.~~11~~ 9 1	
----------NOTES----------	
1. All DG starts may be preceded by an engine prelube period.	
2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR.	

Verify on an actual or simulated loss of offsite power signal:	{~~18~~ months} 24 2
a. De-energization of emergency buses;	
b. Load shedding from emergency buses; and	
c. DG auto-starts from standby condition and:	
1. energizes permanently connected loads in ≤ {~~10~~} seconds, 13.20 2	
2. energizes auto-connected shutdown loads through {automatic load sequencer}, 1	
3. maintains steady state voltage ≥ {~~3744~~} V and ≤ {~~4576~~} V, 3950 4370	
4. maintains steady state frequency ≥ {58.8} Hz and ≤ {61.2} Hz, and	
5. supplies permanently connected and auto-connected shutdown loads for ≥ {5} minutes.	

<4.8.1.1.2.e.4 "***" Footnote>
<4.8.1.1.2.e.4 "+" Footnote>
<4.8.1.1.2.e.4 "*" Footnote>
<4.8.1.1.2.e.4 "**" Footnote>

TSTF-8 not adopted 12

for Divisions 1 and 2 only 17 16

for Division 1 and 2 DGs only 17

2

for Division 1 and 2 DGs and supplies permanently connected shutdown loads for ≥ 5 minutes for Division 3 DG 17 16

(continued)

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.8.1.10 (4.8.1.1.2.a.5) (DOC M.11)	
----------NOTES----------	
1. All DG starts may be preceded by an engine prelube period.	TSTF-8 Not adopted
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:	{18 months} 24
a. In ≤ {10} seconds after auto-start and during tests, achieves voltage ≥ {3744} V and ≤ [4576] V;	
b. In ≤ {10} seconds after auto-start and during tests, achieves frequency ≥ {58.8} Hz and ≤ {61.2} Hz;	frequency ≥ {58.8} Hz for Division 1 and 2 DGs and ≥ 58.0 Hz for Division 3 DGs
c. Operates for ≥ {5} minutes;	Steady state voltage ≥ [3744] V and ≤ [4576] V and
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) to from the offsite power system.	TSTF-163

required

for Division 1 and 2 DGs and ≥ 3820 V for Division 3 DGs

3950

for Divisions 1 and 2 only

TSTF-163

3950

4,370

(continued)

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
<4.8.1.1.2.a.11> SR 3.8.1.~~7~~ 15 ----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. TSTF-8 not adopted 12 ---------- Verify, with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation~~; and~~ 2 b. Automatically energizing the emergency load from offsite power.	24 2 ~~{18~~ months~~}~~
<4.8.1.1.2.a.12> SR 3.8.1.~~8~~ 1 16 ----------NOTE---------- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. TSTF-8 not adopted 12 ---------- for the Division load 2 DGs only. 17 Verify interval between each sequenced load block is within ± ~~{10%~~ of design interval~~}~~ ~~for each load sequence~~ automatic 2 time delay relay	24 2 ~~{18~~ months~~}~~ 2

(continued)

<CTS>

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE	FREQUENCY
SR 3.8.1.17 ----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ----------	TSTF-8 not adopted
Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ {10} seconds, 2. energizes auto-connected emergency loads through load sequencer; 3. achieves steady state voltage ≥ {3744} V and ≤ {4576} V, 4. achieves steady state frequency ≥ {58.8} Hz and ≤ {61.2} Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ {5} minutes.	{18} months; for Divisions 1 and 2 only

(continued)

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS 3.8.1 - AC SOURCES — OPERATING

1. This bracketed requirement has been deleted because it is not applicable to NMP2. The following requirements have been renumbered, where applicable, to reflect this deletion.

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

3. The proper NMP2 plant specific nomenclature/value has been provided.

4. The NMP2 design is such that the loss of one offsite circuit will result in, at most, only Divisions 1 and 3 or Divisions 2 and 3 losing offsite power. When Divisions 2 and 3 are without offsite power, the remaining division (Division 1) has sufficient loads to meet the accident conditions. Therefore, limiting the time to restore the offsite circuit to 24 hours is not necessary. In addition, the current licensing basis does not require this more limiting time. When an offsite circuit is inoperable and it results in the loss of offsite power to Divisions 1 and 3, then both HPCS and LPCS Systems do not have offsite power. This condition should be limited since the accident analysis assumes at least one of these two systems is Operable. Therefore, the Completion Time has been modified to specifically state that the 24 hour time is applicable only when HPCS and LPCS Systems have no offsite power.

5. The proper NMP2 plant specific LCO number has been provided.

6. The word in ISTS SR 3.8.1.19.c.3 and 4 has been changed from "achieves" to "maintain" for consistency with ISTS SR 3.8.1.11.

7. ISTS SR 3.8.1.7 requires the DG start to be timed every 184 days. All other DG starts are allowed to be performed using idling and gradual acceleration to synchronous speed as shown in ISTS SR 3.8.1.2 Note 3. The NMP2 DG vendor does not recommend slow start procedures. All DG starts at NMP2 involve starting the DG to synchronous speed within the time assumed in the accident analysis. The current NMP2 Technical Specifications reflect this requirement, in that slow starts are not allowed. Therefore, there is no reason to maintain a separate 184 day DG test in the ITS. Thus ISTS SR 3.8.1.7 has been deleted and the time requirement has been added to ISTS SR 3.8.1.2 (ITS SR 3.8.1.2). Due to this change, Note 3 to ISTS SR 3.8.1.2 is also not needed and has not been included in ITS SR 3.8.1.2, since no DG start will use modified start procedures. While ISTS SR 3.8.1.7 did not provide a warmup allowance during the 184 day test, ISTS SR 3.8.1.2 Note 2 was not modified to preclude the warmup period prior to loading once per 184 days based on an NRC Request for Additional Information comment provided in an NRC letter dated 5/10/99. In addition, TSTF-163 modified the voltage and frequency ranges that must be met during the 184 day test. Since this test is now essentially performed in ITS SR 3.8.1.2, the TSTF-163 change has been adopted in ITS SR 3.8.1.2. Due to the deletion of ISTS SR 3.8.1.7, the remaining SRs have been renumbered and ISTS SR 3.8.1.3 Note 4 has been modified to delete the reference to ISTS SR 3.8.1.7. B

16. Note 2 to ISTS SR 3.8.1.14 has been revised to permit performance of the 24-hour load test in MODES 1 and 2 in accordance with the requirements of the NMP2 Facility Operating License Amendment No. 64, dated March 7, 1995. This amendment allows performance of this test during power operation provided that the other remaining diesel generators are Operable.

17. While the NMP2 design for the Division 3 4.16 kV emergency bus includes a load shedding scheme, the loads are re-energized immediately upon restoration of power; the loads are not sequenced back onto the emergency buses through load timers. Thus, even if the loads are not shed, the DG will still operate and pick up loads when it re-energizes the emergency bus. In addition, the Division 3 DG does not have any auto-connected shutdown loads on a loss of offsite power. Therefore, ISTS SR 3.8.1.11, ISTS SR 3.8.1.12, and ISTS SR 3.8.1.19 have been modified to exclude these requirements for Division 3.

    The maintaining of permanently connected loads energized from the offsite circuit is not required to be tested for the Division 3 4.16 kV emergency bus during the LOCA test. The NMP2 design for the Division 3 4.16 kV emergency bus does not include any additional permanently connected loads that are not adequately tested by ITS SR 3.8.1.9, the LOOP test, and ITS SR 3.8.1.17, the LOCA/LOOP test. The connection of the auto-connected emergency (LOCA) loads onto the Division 3 4.16 kV emergency bus is not dependent upon the source of the power supply to the 4.16 kV emergency bus. The emergency loads are connected in an identical manner, regardless of whether the power supply to the 4.16 kV emergency bus is the DG or an offsite circuit. The proper operation of the Division 3 auto-connected emergency loads is verified by ITS SR 3.8.1.17, the LOCA/LOOP test. Therefore, ISTS SR 3.8.1.12 has been modified to exclude these requirements for Division 3.

    The NMP2 design for the Division 3 4.16 kV emergency bus only includes one major load block, the HPCS pump. Therefore, ISTS SR 3.8.1.18 has been modified to exclude this requirement for Division 3.

    These changes are consistent with current licensing basis, which does not include these requirements in the CTS.

B

<CTS>

T 4.8.2.1-1
<DOC L.2>

Table 3.8.6-1 (page 1 of 1)
Battery Cell Parameter Requirements

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: ~~ALLOWABLE~~ LIMITS FOR EACH CONNECTED CELL
Electrolyte Level	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[a]	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[a]	Above top of plates, and not overflowing
Float Voltage	≥ 2.13 V	≥ 2.13 V	> 2.07 V
Specific Gravity[b][c]	≥ ~~{0.195}~~ 1.200	≥ ~~{1.190}~~ 5 AND Average of all connected cells > ~~{1.200}~~ 5	Not more than 0.020 below average of all connected cells AND Average of all connected cells ≥ ~~{1.190}~~ 5

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during and following equalizing charges provided it is not overflowing. 5

(b) Corrected for electrolyte temperature and level. Level correction is not required, however, when battery charging is < ~~{2}~~ amps when on float charge. 6 B

(c) A battery charging current of < ~~{2}~~ amps when on float charge is acceptable for meeting specific gravity limits following a battery recharge, for a maximum of ~~{7}~~ days. When charging current is used to satisfy specific gravity requirements, specific gravity of each connected cell shall be measured prior to expiration of the ~~{7}~~ day allowance. 1

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, REVISION 1
ITS 3.8.6 - BATTERY CELL PARAMETERS

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

2. The word "values" in the third Condition of Condition B has been changed to "limits" to more closely match the LCO description. In addition, the word "Allowable" in Table 3.8.6-1 has been deleted to be consistent with the manner in which Category C "Limits" are described in the ACTIONS. This will also avoid confusion with the term "Allowable Value" used in the Instrumentation Section.

3. The second and third Frequencies of SR 3.8.6.2 have been modified to require the parameters to be verified within 7 days after the battery discharge/overcharge event, in lieu of the ISTS requirements of 24 hours after the battery discharge/overcharge event. IEEE-450 (the 1980, 1987, and 1995 versions) only require the verification to be performed; it does not state the time limit for performing the verification. Therefore, the time specified in the NMP2 CTS is being maintained (i.e., this time is consistent with current licensing basis).

4. Typographical/grammatical error corrected.

5. The words "and following" have been added to footnote (a) to allow the electrolyte level to be temporarily above the limit following the equalize charge as well as during the charge. As stated in the Bases for this footnote (in Table 3.8.6-1 description), IEEE-450 recommends that electrolyte level readings not be taken until 72 hours after the equalize charge. This allows time for the electrolyte temperature to stabilize and the level reading to be a "true" reading. Without the added words, the limit may not be met upon completion of the charge and unnecessary ACTIONS would have to be taken.

6. The allowance to not correct specific gravity for electrolyte level when charging current is < 2 amps when the battery is on float charge has not been adopted in the ITS. This is consistent with current licensing basis, which always requires specific gravity to be corrected for electrolyte level. B

BASES

Emergency Core Cooling System (ECCS) and Reactor Core Isolation Cooling (RCIC) System

APPLICABLE SAFETY ANALYSES (continued)

Section 3.6, ~~Reactor Coolant System (RCS)~~; and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

Reference 7

AC sources satisfy the requirements of Criterion 3 of ~~the~~ ~~NRC Policy Statement~~.

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System, and three separate and independent DGs ~~(11, 12, and 13)~~, ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the ~~FSAR~~ and are part of the licensing basis for the unit.

~~In addition, [one required automatic load sequencer per ESF bus] shall be OPERABLE. In general, Division 3 does not have a load sequencer since it has only one large load (i.e., the high pressure core spray (HPCS) pump). In such cases the LCO should refer to the Division 1 and 2 sequencers only.~~

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ~~ESF~~ buses. Each offsite circuit consists of incoming breaker and disconnect to the respective service transformers ~~(10)~~ and ~~(20)~~, the ~~(10)~~ ~~and~~ ~~(20)~~ ~~service~~ transformers, ~~the ESF transformers 11 and 21,~~ and the respective circuit path including feeder breakers to the 4.16 kV ~~ESF~~ buses.

From the 345kV/45kV Scriba Substation

the reserve station

4.16 kV emergency

2RTX-XSR1A

2RTX-XSR1B

and auxiliary boiler transformer 2ABS-X1

emergency

and 2ABS-X1

respective 2RTX-XSR1A,

2RTX-XSR1B

(continued)

In addition, proper sequencing of loads is a required function for offsite circuit OPERABILITY.

BASES

The 13.20 second start time includes the Loss of Voltage—Time Delay Function Allowable Value specified in LCO 3.3.8.1

LCO (continued)

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot and DG in standby with engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

13.20

4.16 kV emergency

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in one division must be separate and independent (to the extent possible) of the AC sources in the other division(s). For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical.

APPLICABILITY

The AC sources ~~and sequencers~~ are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

A Note has been added taking exception to the Applicability requirements for Division 3 sources, provided the HPCS System is declared inoperable. This exception is intended to allow declaring of the Division 3 inoperable either in lieu of declaring the Division 3 source inoperable, or at any time subsequent to entering ACTIONS for an inoperable Division 3 source. This exception is acceptable since, with the Division 3 inoperable and the associated ACTIONS

(continued)

BASES

ACTIONS (continued)

B.4

According to Regulatory Guide 1.93 (Ref. 8), operation may continue in Condition B for a period that should not exceed 72 hours. In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 established a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action C.1 reduces the vulnerability to a loss of

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of [3740] V is [90%] of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. [1]), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90%, or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of [5760] V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. [3]).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by Notes (Note 1 for SR 3.8.1.7 and Note 2 for SR 3.8.1.2) to indicate that all DG starts for these

(continued)

In addition, to minimize wear and tear on the DG, the Note also allows all DG starts to be

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of this testing, (Division 1 and 2 DGs only) the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil (lube) are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

~~In order to reduce stress and wear on diesel engines, some manufacturers recommend that the starting speed of DGs be limited, that warmup be limited to this lower speed, and that DGs be gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 2, which is only applicable when such procedures are recommended by the manufacturer.~~ TSTF-253

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 10 seconds. The 10 second start requirement supports the assumptions in the design basis LOCA analysis (Ref. 10). ~~The 10 second start requirement may not be applicable to SR 3.8.1.2 (see Note 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 10 second start requirement of SR 3.8.1.7 applies. Since SR 3.8.1.7 does require a 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-253

Insert SR 3.8.1.2 TSTF-163

The ~~[illegible]~~ 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. 6). ~~The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7).~~ These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting ~~greater than or equal to the~~ a load approximately equivalent to that corresponding to the continuous rating.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

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.

SR 3.8.1.11

As required by Regulatory Guide 1.108 (Ref. 8), paragraph C.2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

This is only required for Divisions 1 and 2 because the loading logic is different based on the power source.

loading logic for loading onto offsite power. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

AC electrical power

The Frequency of [18 months] takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the [18 month] Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for the Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil (Division 1 and 2 DGs only) being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

lube

TSTF-8 not adopted

SR 3.8.1.13

Consistent with Regulatory Guide 1.9 (Ref. 11), paragraph C.2.2.12)

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ECCS initiation test signal and critical protective functions (engine overspeed, and generator differential current)

(continued)

BASES

LCO (continued)

ESF bus required OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Similarly, when the high pressure core spray (HPCS) is required to be OPERABLE, a separate offsite circuit to the Division 3 Class 1E onsite electrical power distribution subsystem, or an OPERABLE Division 3 DG, ensures an additional source of power for the HPCS. This additional source for Division 3 is not necessarily required to be connected to be OPERABLE. Either the circuit required by LCO Item a., or a circuit required to meet LCO Item c. may be connected, with the second source available for connection. Together, OPERABILITY of the required offsite circuit(s) and DG(s) ensure the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents, reactor vessel draindown).

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to their respective ESF bus(es), and of accepting required loads during an accident. Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the plant. The offsite circuit consists of incoming breaker and disconnect to the respective service transformers 1 and 21 the 11 and 21 service transformers, the ESF transformers A1 and B1, and the respective circuit path including feeder breakers to all 4.16 kV ESF buses required by LCO 3.8.10.

The required DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

(continued)

BASES

LCO (continued)

2 The necessary portions of the Service Water System and Ultimate Heat Sink capable of providing cooling to the required DG(s) are also required.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY. In addition, proper sequencer operation is an integral part of offsite circuit OPERABILITY since its inoperability impacts on the ability to start and maintain energized loads required OPERABLE by LCO 3.8.10.

It is acceptable for divisions to be cross tied during shutdown conditions, permitting a single offsite power circuit to supply all required divisions. [No fast transfer capability is required for offsite circuits to be considered OPERABLE.]

As described in Applicable Safety Analyses, in the event of an accident during shutdown, the TS are designed to maintain the plant in a condition such that, even with a single failure, the plant will not be in immediate difficulty.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the [primary or secondary] containment provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel 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.

The AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1 (continued)

provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.3.2

99 gallon

For the Division 1 and 2 DGs and the 168 gallon requirement for the Division 3 DG are

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each DG. The 500 gal requirement is based on the DG manufacturer's consumption values for the run time of the DG. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage location to the DG when the DG lube oil sump does not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level.

(above the manufacturers minimum recommended levels)

The 7 day inventory can be in the engine oil sump or a combination of the engine oil sump and remote storage location.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run times are closely monitored by the plant staff.

SR 3.8.3.3

of new fuel oil prior to addition to the storage tanks

The tests, listed below, are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion and operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-~~f~~ ~~k~~ (Ref. ~~8~~);

b. Verify in accordance with the tests specified in ASTM D975-~~k~~ ~~k~~ (Ref. ~~6~~) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 ~~or~~ an API gravity at 60°F of ≥ 27 and ≤ 39 ~~a~~

(continued)

(1) the sample has an API gravity of within 0.3° at 60°F or a specific gravity of within 0.0018 at 60/60°F, when compared to the supplier's certificate, or

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes; and a flash point of ≥ 125°F; and

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-~~[illegible]~~ ~~[illegible]~~ (Ref. ~~[illegible]~~).

within 31 days following addition of the new fuel oil to the fuel oil storage tank(s)

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-~~[illegible]~~ ~~[illegible]~~ (Ref. ~~[illegible]~~) are met for new fuel oil when tested in accordance with ASTM D975-~~[illegible]~~ ~~[illegible]~~ (Ref. ~~[illegible]~~), except that the analysis for sulfur may be performed in accordance with ASTM D1552-~~[illegible]~~ ~~[illegible]~~ (Ref. ~~[illegible]~~) or ASTM D2622-~~[illegible]~~ ~~[illegible]~~ (Ref. ~~[illegible]~~). The 31 day period is acceptable because the fuel oil properties of interest, even if not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, mostly due to oxidation. The presence of particulate does not mean that the fuel oil will not burn properly in a diesel engine. However, the particulate can cause fouling of filters and fuel oil injection equipment, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276-~~[illegible]~~ ~~[illegible]~~, Method A (Ref. ~~[illegible]~~). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. ~~[For those designs in which the total volume of stored fuel oil is contained in two or more interconnected tanks, each tank must be considered and tested separately.]~~

The Frequency of this Surveillance takes into consideration fuel oil degradation trends indicating that particulate

(continued)

(The test can consist of a single rate if the test rate employed for the performance discharge test exceeds the 1 minute rate.)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.7 (continued)

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

This substitution is acceptable because a modified performance discharge test represents a more severe test of battery capacity than SR 3.8.4.7

The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

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.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

Category C defines the limit for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limit, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

Appendix C

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensures that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C Allowable value for float voltage is based on IEEE-450 (Ref. 3), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

limit

The Category C limit of average specific gravity (≥ 1.195), is based on manufacturer's recommendations (0.020 below the manufacturer's recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

more

a cell with a marginal or unacceptable specific gravity is not masked by averaging with cells having higher specific gravities.

The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity. Footnote (b) in Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature with the exception that level correction is not required when battery charging current is < 2 amps on float charge. This current provides, in general, an indication of overall battery condition.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote (c) to Table 3.8.6-1 allows the float charge

ing

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the AC and DC electrical power sources and associated distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite or onsite AC electrical power; and

b. A worst case single failure.

The AC, DC, and AC vital bus electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement.

LCO

The required AC, DC, and AC vital bus power distribution subsystems listed in Table B 3.8.8-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The Division 1, 2, and 3 AC, DC, and AC vital bus electrical power primary distribution subsystems are required to be OPERABLE.

Maintaining the Division 1, 2, and 3 AC, DC, and AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Any two of the three divisions of the distribution system are capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any system or within the electrical power distribution subsystems does not prevent safe shutdown of the reactor.

As noted in Table 3.8.8-1 (Footnote a), each division of the AC, DC, and 120 VAC uninterruptible electrical power distribution systems is a subsystem.

OPERABLE AC electrical power distribution subsystems require the associated buses to be energized to their proper voltages. OPERABLE DC electrical power distribution

(continued)

BASES

LCO (continued)

subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE ~~vital bus~~ electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated ~~inverter~~ via inverted DC voltage, inverter using internal AC source, or Class 1E ~~constant voltage~~ transformer~~s~~.

In addition, tie breakers between ~~redundant~~ safety related AC, ~~DC, and AC vital bus~~ power distribution subsystems ~~if they exist,~~ must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the ~~affected redundant~~ electrical power distribution subsystems are considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained, in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 4 and 5 are covered in the Bases for LCO 3.8.10, "Distribution Systems—Shutdown."

ACTIONS

A.1

With one or more Division 1 ~~or~~ 2 required AC buses, load centers, motor control centers, or distribution panels (except AC ~~vital buses~~), ~~in one division~~ inoperable, the

(continued)

BASES

ACTIONS

E.1 (continued)

declaring the High Pressure Core Spray inoperable allows the ACTIONS of LCO 3.5.1, "ECCS—Operating," to apply appropriate limitations on continued reactor operation.

E.1

Condition F corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. When more than one Condition is entered, and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

Having this Surveillance verifies that the AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter [6].
2. FSAR, Chapter [15].
3. Regulatory Guide 1.93, December 1974.

2

INSERT SR 3.8.8.1

This is normally performed by verifying correct voltage for the AC and DC switchgear and by verifying that no inoperability status indicator lights (that indicate a loss of power to one or more of the required load centers, motor control centers (MCCs), or distribution panels) are lit in the control room. Alternately, when the normal method is not available, verification that a load powered from the associated bus is energized is also acceptable.

2

INSERT SR 3.8.9.1

This is normally performed by verifying correct voltage for the AC and DC switchgear and by verifying that no inoperability status indicator lights (that indicate a loss of power to one or more of the required load centers, MCCs, or distribution panels) are lit in the control room. Alternately, when the normal method is not available, verification that a load powered from the associated bus is energized is also acceptable. B

L.10 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The diesel generators (DGs) are used to support mitigation of the consequences of an accident; however, they are not considered the initiator of any previously analyzed accident. As such, the elimination of a warmup restriction and a time requirement to load the DG during surveillance testing will not increase the probability of any accident previously evaluated. The proposed SR continues to provide adequate assurance of OPERABLE DGs and therefore, does not involve an increase in the consequences of any accident previously evaluated. B

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change does not involve a significant reduction in a margin of safety since the manual loading of the DGs does not impact the capability of the DGs to perform their safety function. In addition, other SRs continue to ensure the DG can be loaded properly during accident conditions.

L.15 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The current surveillance requirements have been changed to update the diesel generator (DG) start and energization times when a loss of offsite power only occurs. The proposed change increases the start and energization time for the Division 1, 2, and 3 DGs from 13 seconds to 13.20 seconds. The change to the DG start and energization time is based on the time assumed for the loss of offsite power accident analysis. The DGs provide emergency standby AC electrical power to support mitigation of the consequences of an accident; however, they are not considered the initiator of any previously analyzed accident. The proposed change to the DG start and energization time does not change the DG design, the mode of operation or maintenance, and is not a physical modification to the plant, nor does the change reduce the effectiveness of the surveillance requirements to demonstrate DG operability, detect equipment degradation, or assure reliability since the Surveillance Requirements continue to satisfy the recommendations of Regulatory Guide 1.9, "Selection, Designs, Qualification, and Testing of Emergency Diesel-Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," Revision 2, December 1979, and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977, which are the bases for the current Surveillance Requirements. Moreover, the proposed change will not affect current commitments related to DG reliability and the Maintenance Rule, which are designed to identify and correct equipment deficiencies and degradation to maintain DG operability and reliability. In addition, the new time is consistent with the current time in the loss of offsite power accident analysis, and this time is identified and is justified in another NSHE in ITS 3.3.8.1. Therefore, the proposed change will not involve a significant increase in the probability or consequences of any accident previously evaluated. B B

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

   The change does not involve a change to the DG design, the mode of operation or maintenance, and is not a physical modification to the plant, nor does the change reduce the effectiveness of the surveillance requirements to demonstrate DG operability, detect equipment degradation, or assure reliability. The new DG start and energization time is consistent with the assumptions of the loss of offsite power

L.15 CHANGE

2. (continued)

analysis. Since plant design, operational methods, and equipment responses are unchanged, no new failure modes or accidents will be created. Therefore, the proposed change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

The proposed change increases the start and energization time for the Division 1, 2, and 3 DGs from 13 seconds to 13.20 seconds. This proposed time is the summation of the current DG start time of 10 seconds (from various CTS 4.8.1.1 Surveillances) and the DG loss of voltage time delay Allowable Value (from CTS Table 3.3.3-2 Trip Functions D.1 and E.1, as modified by an "L" Discussion of Change in ITS 3.3.8.1). The first time has been previously approved by the NRC and the second time is justified in another NSHE. This is also the time assumed in the accident analysis for the DG to start when only a loss of voltage occurs. The current time in CTS 4.8.1.1.2.e.4.a)2) and b)2) is essentially the allowed DG start and energization time rounded to the nearest whole second. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

L.22 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The Division 3 offsite power sources are used to support mitigation of the consequences of an accident; however, they are not considered the initiator of any previously analyzed accident. As such, additional time for repair of an inoperable Division 3 offsite power source will not increase the probability of any accident previously evaluated. The ITS ACTIONS continues to provide adequate assurance of OPERABLE Division 3 offsite power sources and the HPCS System and therefore, does not involve an increase in the consequences of any accident previously evaluated.

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

   The proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant. Therefore, it does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   This change does not involve a significant reduction in a margin of safety since the OPERABILITY of the HPCS System continues to be required. In addition, the proposed restoration time is consistent with that previously approved by the NRC for an inoperable HPCS DG and an inoperable HPCS System.

Volume 10
Sections 3.9 and 3.10

Section 3.9

ADMINISTRATIVE (continued)

A.6 CTS 4.1.3.5 requires each control rod scram accumulator to be verified OPERABLE every 7 days "unless the control rod is inserted and disarmed or scrammed." Stating the conditions for an exception to performance of the accumulator Surveillance that are equivalent to the Applicability of the LCO is unnecessary. If the accumulator is not required to be Operable, CTS 4.0.1 (proposed SR 3.0.1) states that Surveillances are not required to be performed. Therefore, these words in CTS 4.1.3.5 (unless the control rod is inserted and disarmed or scrammed) have been deleted and this deletion is administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 A new requirement has been added for control rod OPERABILITY during refueling, i.e., each withdrawn control rod must be capable of insertion (by scram). This new requirement will be covered as part of the current requirement for a withdrawn control rod to be OPERABLE. A Surveillance Requirement (proposed SR 3.9.5.1) has also been added. Thus, if the new Surveillance Requirement is not met, the withdrawn control rod will be inoperable. In addition, an appropriate ACTION (ITS 3.9.5 ACTION A) has been added to provide proper actions if the control rod is inoperable due to this new reason. These changes represent additional restrictions on plant operations necessary to ensure the control rod scram function is available for mitigation should a prompt reactivity excursion occur during refueling. B

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

None

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

L.1 The scram accumulator leak detectors, pressure detectors, and associated alarm in CTS 4.1.3.5.b do not necessarily relate directly to accumulator OPERABILITY. The BWR Standard Technical Specifications, NUREG-1434, Rev. 1, do not typically require indication-only or test equipment to be OPERABLE to support OPERABILITY of a system or component. Control of the availability of, and necessary compensatory activities if not available, for indications, monitoring instruments, alarms, and test equipment is an issue for plant operational procedures and policies. The requirement to ensure scram accumulator pressure is adequate to perform the safety related scram function of the control rod is maintained as proposed SR 3.9.5.2. Therefore, the control rod accumulator leak detectors, pressure detectors, and alarm Surveillances are proposed to be deleted. B

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, 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 proposed TSTF-232. 1 B

2. The current licensing basis of NMP2 refueling equipment interlocks have been provided.

BASES

LCO (continued)

blocks to prevent operations that could result in criticality during refueling operations.

APPLICABILITY

In MODE 5, a prompt reactivity excursion could cause fuel damage and subsequent release of radioactive material to the environment. The refueling equipment interlocks protect against prompt reactivity excursions during MODE 5. The interlocks are only required to be OPERABLE during in-vessel fuel movement with refueling equipment associated with the interlocks.

when the reactor mode switch is in the refuel position. The interlocks are not required when the reactor mode switch is in the shutdown position since a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures control rod withdrawals cannot occur simultaneously with in-vessel fuel movements

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, the refueling interlocks are not required to be OPERABLE in these MODES.

3

ACTIONS

A.1 A.2.1, and A.2.2 TSTF-225

Insert Action A.1a

B

TSTF-225 and 2

With one or more of the required refueling equipment interlocks inoperable, the unit must be placed in a condition in which the LCO does not apply. In-vessel fuel movement with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn). Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

Insert Action A.1b

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

(continued)

L.1 CHANGE

In accordance with the criteria set forth in 10 CFR 50.92, NMPC has evaluated this proposed Technical Specifications change and determined it does not represent a significant hazards consideration. The following is provided in support of this conclusion.

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

   The scram accumulator leak detectors, pressure detectors, and associated alarm are not assumed in the initiation of any analyzed event. The requirements for this instrumentation does not need to be explicitly stated in the Technical Specifications. The scram accumulator pressure is still required to be checked per SR 3.9.5.2. One method to perform the verifications required for SR 3.9.5.2 would require instrumentation to be Operable. As a result, accident consequences are unaffected by this change. Therefore, this change will not involve a significant increase in the probability or consequences of an accident previously evaluated. B

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

   The possibility of a new or different kind of accident from any accident previously evaluated is not created because the proposed change does not introduce a new mode of plant operation and does not involve physical modification to the plant.

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

   The proposed deletion of the scram accumulator leak detectors, pressure detectors, and associated alarm requirements from Technical Specifications does not impact any margin of safety. The requirements for this instrumentation does not need to be explicitly stated in the Technical Specifications. The scram accumulator pressure is still required to be checked per SR 3.9.5.2. One method to perform the verifications required for SR 3.9.5.2 would require the instrumentation to be Operable. As a result, the Operability of the instrumentation will normally be maintained to satisfy SR 3.9.5.2 without the need for explicit instrumentation requirements in the Technical Specifications. Therefore, this change does not involve a significant reduction in a margin of safety.

Section 3.10

A.1

Specification 3.10.1

SPECIAL TEST EXCEPTIONS

3/4.10.7 SYSTEM LEAKAGE AND HYDROSTATIC TESTING

LIMITING CONDITION FOR OPERATION

LCO 3.10.1 3.10.7 When conducting system leakage or hydrostatic testing, the average reactor coolant temperature specified in Table 1.2 for OPERATIONAL CONDITION 4 may be increased above 200°F, and operation considered not to be in OPERATIONAL CONDITION 3, to allow performance of a system leakage or hydrostatic test provided the maximum reactor coolant temperature does not exceed 212°F and the following OPERATIONAL CONDITION 3 LCO's are met:

LA.1

LCO 3.10.1.a a. 3.3.2, "Isolation Actuation Instrumentation", Functions 1.a.2, 1.b and 3.a and b of Table 3.3.2-1;

add LCO 3.10.1.b

L.1

LCO 3.10.1.c b. 3.6.5.1, "Secondary Containment Integrity";

A.3

LCO 3.10.1.d c. 3.6.5.2, "Secondary Containment Automatic Isolation Dampers"; and

LCO 3.10.1.e d. 3.6.5.3, "Standby Gas Treatment System."

APPLICABILITY: OPERATIONAL CONDITION 4, with average reactor coolant temperature >200°F.

A.4

add proposed ACTIONS NOTE

add proposed Required Action A.1 Note

ACTION:

ACTION A With the requirements of the above specification not satisfied, immediately enter the applicable condition of the affected specification or immediately suspend activities that could increase the average reactor coolant temperature or pressure and reduce the average reactor coolant temperature to ≤200°F within 24 hours.

SURVEILLANCE REQUIREMENTS

SR 3.10.1.1

4.10.7 Verify applicable OPERATIONAL CONDITION 3 surveillances for specifications listed in 3.10.7 are met.

Page 1 of 3

A.1

Specification 3.10.1

REACTOR COOLANT SYSTEM

3/4.4.9 RESIDUAL HEAT REMOVAL

HOT SHUTDOWN

See Discussion of Changes for ITS: 3.4.9, "RHR Shutdown Cooling - Hot Shutdown," in Section 3.4

LIMITING CONDITIONS FOR OPERATION

3.4.9.1 Two* shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and, unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation**, † with each loop consisting of at least: A.5

a. One OPERABLE RHR pump, and
b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 3, with reactor vessel pressure less than the RHR cut-in permissive setpoint.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible. Within 1 hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop. Be in at least COLD SHUTDOWN within 24 hours.††

b. With no RHR shutdown cooling mode loop in operation, immediately initiate corrective action to return at least one loop to operation as soon as possible. Within 1 hour, establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.1 At least one shutdown cooling mode loop of the residual heat removal system or alternative method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

---

* One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation.

** The shutdown cooling pump may be removed from operation for up to 2 hours per 8-hour period provided the other loop is OPERABLE.

† ~~The RHR shutdown cooling mode loop may be removed from operation during hydrostatic and system leakage testing.~~ A.5 B

†† Whenever two or more RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat-removal methods.

A.1

Specification 3.10.1

REACTOR COOLANT SYSTEM

RESIDUAL HEAT REMOVAL

COLD SHUTDOWN

LIMITING CONDITIONS FOR OPERATION

3.4.9.2 Two* shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and, unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation** † with each loop consisting of at least: LCO 3.10.1

a. One OPERABLE RHR pump, and
b. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 4.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, within 1 hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop.

b. With no RHR shutdown cooling mode loop in operation, within 1 hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.2 At least one shutdown cooling mode loop of the residual heat removal system or alternative method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

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* One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation.

** The shutdown cooling pump may be removed from operation for up to 2 hours every 8-hour period provided the other loop is OPERABLE.

† The shutdown cooling mode loop may be removed from operation during hydrostatic and system leakage testing. LCO 3.10.1 B

See Discussion of Changes for ITS: 3.4.10, "RHR Shutdown Cooling-Cold Shutdown," in Section 3.4

ADMINISTRATIVE

A.1 In the conversion of the Nine Mile Point Unit 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 Technical Specification (ISTS)).

A.2 Not used. 1 B

A.3 CTS 3.8.4.4 requires the RPS electric power monitoring assemblies for each RPS logic bus to be Operable at all times. In ITS 3.3.8.2, the Applicability has been changed to only require the assemblies when instrumentation powered by the RPS logic buses are required (See Discussion of Change L.1 for ITS: 3.3.8.2). ITS 3.3.8.2 does not require the assemblies to be Operable at all times when in MODE 4, which is the Applicability of this LCO (ITS 3.10.1). The RPS logic buses provide power to the secondary containment isolation instrumentation, thus the assemblies are needed for Operability of the instrumentation. To maintain consistency with the current requirements, ITS 3.10.1 will now require ITS 3.3.8.2, "RPS Electric Power Monitoring — Logic" to be Operable during a system leakage or hydrostatic leak test. This will ensure the secondary containment isolation instrumentation that is required by ITS 3.10.1 can perform its intended function. ITS 3.10.1 ACTION A also requires the actions of ITS 3.3.8.2 to be taken when the assemblies are inoperable and proposed SR 3.10.1.1 requires the SRs of the applicable LCOs to be performed. Since these new requirements are consistent with the current requirements, except as discussed in the Discussion of Changes for ITS 3.3.8.2, this change is considered administrative.

A.4 Two new Notes have been added to the CTS 3.10.7 Action for clarity. The ITS 3.10.1 ACTIONS Note has been added to clarify that the CTS 3.10.7 Action requirement to enter the applicable condition of the affected Specification applies for each of the affected Specifications (as shown in the current LCO, there are four potentially affected Specifications). ITS 3.10.1 Required Action A.1 Note has been added to clarify that, upon entry into the ACTIONS of an affected Specification as required by the CTS 3.10.7 Action, if the affected Specifications ACTIONS state to be in MODE 4, this includes reducing average coolant temperature to ≤ 200°F. This is consistent with the second part of the CTS 3.10.7 Action. Since these Notes have been added for clarity, they are considered administrative changes.

ADMINISTRATIVE (continued)

A.5 CTS 3.4.9.1, which requires an RHR shutdown cooling loop to be in operation in Operational Condition 3 with the reactor vessel pressure less than the RHR cut-in permissive pressure, is modified by footnote † exempting the requirement during hydrostatic testing. The unit is not considered to be in Operational Condition 3 during the hydrostatic test (or system leakage testing). CTS 3.10.7 specifically states that the unit is not considered to be in Operational Condition 3; it remains in Operational Condition 4. Therefore, footnote † to CTS 3.4.9.1 is not needed and its deletion is considered administrative. 16

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The maximum temperature allowed during the inservice leak (system leakage) or hydrostatic test specified in CTS 3.10.7 (212°F) is proposed to be relocated to the USAR. System leakage and hydrostatic tests are very controlled evolutions involving strict procedural compliance. As a result, the maximum temperature limitation is not necessary to be included in the Technical Specifications to ensure a system leakage or hydrostatic test is conducted in accordance with USAR and plant procedural requirements which include the maximum temperature limitation. Therefore, the relocated requirement is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the USAR will be controlled by the provisions of 10 CFR 50.59.

"Specific"

L.1 CTS 3.10.7.a requires CTS 3.3.2, "Isolation Actuation Instrumentation," Function 1.b, Drywell Pressure - High, to be Operable during inservice leak (system leakage) and hydrostatic testing. This requirement is not included in ITS 3.10.7. During system leakage and hydrostatic testing, the unit is

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) considered to be in Mode 4. In this Mode, neither the primary containment, nor its support functions (the primary containment air lock and the primary containment isolation valves) are required to be Operable; e.g., the primary containment is not required to be leak tight, nor are the air lock doors required to be closed. In order to conduct the visual examinations associated with system leakage and hydrostatic testing, the air lock doors are normally left open for easy access. Therefore, it is not possible to receive a high drywell pressure signal since there is no way to pressurize the primary containment. As such, requiring the Drywell Pressure - High Function to be Operable does not provide any real safety benefit. In addition, the accident analysis assumes CTS 3.3.2, Function 1.a.2, Reactor Vessel Water Level - Low, Low, Level 2, (ITS 3.3.6.2, Function 1 provides the signal to isolate the secondary containment and start the SGT System. This Function, currently required by CTS 3.10.7.a, is being maintained in ITS LCO 3.10.7.a.

Volume 11
Chapters 4.0 and 5.0

Chapter 4.0

A.1

Chapter 4.0

TABLE 5.7.1-1

REACTOR CYCLIC OR TRANSIENT LIMITS AND DESIGN CYCLE OR TRANSIENT

CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
120 heatup and cooldown cycles	70°F to 565°F to 70°F
80 step change cycles	Loss of feedwater heaters
198 reactor trip cycles	100% to 0% of RATED THERMAL POWER
130 hydrostatic and system leakage tests	Pressurized to ≥930 psig and ≤1250 psig

B

A.6

moved to Specification 5.5.5

Chapter 5.0

5.2 Organization

5.2.2 Unit Staff (continued)

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;

2. An individual should not be permitted to work more than 16 hours in any 24 hour period, nor more than 24 hours in any 48 hour period, nor more than 72 hours in any 7 day period, all excluding shift turnover time;

3. A break of at least 8 hours should be allowed between work periods, including shift turnover time; and

4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized in advance by the plant manager or a designee, in accordance with approved administrative procedures, or by higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation.

Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by a specified corporate officer or a designee to ensure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized.

f. The operations supervisors shall hold an SRO license.

g. The Shift Technical Advisor (STA) shall provide advisory technical support to the shift supervision 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. 1B

5.5 Programs and Manuals (continued)

5.5.4 Radioactive Effluent Controls Program

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

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

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to ten times the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20.1001-20.2402; B

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

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

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

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

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas at or beyond the site boundary shall be in accordance with the following: B

(continued)

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

1. For noble gases: a dose rate ≤ 500 mrems/yr to the whole body and a dose rate ≤ 3000 mrems/yr to the skin, and B

2. For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives greater than 8 days: a dose rate ≤ 1500 mrems/yr to any organ; B B

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

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

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

k. Limitations on venting and purging of the primary containment through the Standby Gas Treatment System to maintain releases as low as reasonably achievable.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Radioactive Effluent Controls Program surveillance frequencies. B

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track the USAR, Table 3.9B-1 Note 5, cyclic and transient occurrences to ensure that components are maintained within the design limits.

5.5.6 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 pumps and valves.

(continued)

5.5 Programs and Manuals

5.5.7 Ventilation Filter Testing Program (VFTP) (continued)

ESF Ventilation System	Penetration	RH
SGT System	0.175	95
CREF System	0.175	95

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters and the charcoal adsorbers is less than the value specified below when tested at the system flowrate specified below:

ESF Ventilation System	Delta P (inches wg)	Flowrate (cfm)
SGT System	< 5.5	3600 to 4400
CREF System	< 5.5	2025 to 2475

e. Demonstrate that the heaters for each of the ESF systems dissipate the value specified below, adjusted to degraded voltage conditions, when tested in accordance with ANSI N510-1980: B

ESF Ventilation System	Wattage (kW)	B
SGT System	14.0 to 17.1	B
CREF System	≥ 7.95	

5.5.8 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Main Condenser Offgas Treatment System and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks.

The program shall include:

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

b. A surveillance program to ensure that the quantity of radioactivity contained in all outside temporary liquid

(continued)

5.5 Programs and Manuals

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

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 ≤ 10 Ci, excluding tritium and dissolved or entrained noble gases.

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:

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, a specific gravity, or an absolute specific gravity within limits,

   2. A flash point and kinematic viscosity within limits for ASTM fuel oil,

   3. A clear and bright appearance;

b. Within 31 days following addition of the new fuel oil to storage tanks, verify that the properties of the new fuel oil, other than those addressed in 5.5.9.a above, are within limits for ASTM fuel oil; and

c. Total particulate concentration of the fuel oil in the storage tanks is ≤ 10 mg/l when tested every 31 days in accordance with ASTM D-2276, Method A.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program test frequencies.

(continued)

Specification 5.2

A.1

TABLE 6.2.2-1

MINIMUM SHIFT CREW COMPOSITION(a)(b)

POSITION	OPERATIONAL CONDITIONS 1, 2	3	4, 5	1, 2, 3, 4, 5
Station Shift Supervisor(d)	1	1	1(e)	1(c)
Assistant Station Shift Supervisor(g)	1	1	None	1(c)
Operator	2, 3(h)	2	1	2(c) 3(c)
5.2.2.a Unlicensed(f)	2	2	1	3(c)
Shift Technical Advisor(g)	1	1	None	1(c)

LA.1 B

LA.2

LA.1

TABLE NOTATIONS

A.4

(a) At any one time more licensed or unlicensed operating people could be present for maintenance, repairs, refuel outages, etc.

(b) The shift crew composition may be one less than the minimum requirements of Table 6.2.2-1 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 of Table 6.2.2-1. This provision does not permit any shift crew position to be unmanned upon shift change because an oncoming shift crewman scheduled to come on duty is late or absent.

5.2.2.c

A.3

5.2.2.a (c) For operation longer than 8 hours without process computer.

A.5 moved to Specification 5.1

(d) Any time the Shift Supervisor is absent from the control room while the unit is in OPERATIONAL CONDITION 1, 2, or 3, the Assistant Station Shift Supervisor when not in the STA function, or another individual with a valid Senior Operator license shall be designated to assume the control room command function. During any absence of the Shift Supervisor from the control room while the unit is in OPERATIONAL CONDITION 4 or 5, an individual with a valid Senior Operator license or Operator license shall be designated to assume the control room command function.

(e) An additional Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities shall supervise all core alterations.

5.2.2.a (f) Those operating personnel not holding an Operator or Senior Operator license.

LA.1

(g) The Assistant Station Shift Supervisor shall hold a Senior Operator's license and, if qualified, may perform the Shift Technical Advisor function when the Site Emergency Plan is activated in OPERATIONAL CONDITIONS 1, 2, or 3, if a dedicated Shift Technical Advisor is not available.

(h) OPERATIONAL CONDITION 2 only.

LA.2

Page 5 of 6

A.1

Specification 5.2

5.2 ORGANIZATION

LA.7

RECORDS

6.2.3.4 Records of activities performed by the ISEG shall be prepared, maintained, and forwarded each calendar month to the Vice President - Nuclear Safety Assessment and Support.

5.2.2.g 6.2.4 SHIFT TECHNICAL ADVISOR

LA.3

Normally, the Shift Technical Advisor (STA) shall be a dedicated position. If, however, a dedicated STA cannot be provided on a shift, then the Assistant Station Shift Supervisor (ASSS) shall function in a dual role (SRO/STA) and assume the duties of the Shift Technical Advisor (STA) when the Emergency Plan is activated in OPERATIONAL CONDITIONS 1, 2 or 3. The STA shall provide advisory technical support to the ~~Shift Supervisor~~ in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to safe operation of the unit. The STA (and the ASSS, when fulfilling the role of the STA) shall have a bachelor's degree in a physical science, engineering, or a Professional Engineer's license issued by examination, and shall have received specific training in the response and analysis of the unit for transients and accidents, and in unit design and layout, including the capabilities of instrumentation and controls in the control room.

A.6

Shift Supervision

B

A.7

6.3 FACILITY STAFF QUALIFICATIONS

Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1978 for comparable positions, except for the Manager Radiation Protection who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975.

6.4 TRAINING

A retraining and replacement training program for the unit staff shall be maintained under the direction of the Manager Training, shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI/ANS 3.1-1978 and 10 CFR 55, and shall include familiarization with relevant industry operational experience. A training program for the Fire Brigade shall be maintained under the direction of the Manager Training and the Supervisor - Fire Protection Nuclear and shall meet or exceed the requirements of Appendix R to 10 CFR 50.

See Discussion of Changes for ITS: 5.3, "Unit Staff Qualifications," in this Section.

See Discussion of Changes for CTS: 6.4, "Training," in this Section.

ADMINISTRATIVE (continued)

A.6 The person to whom the STA provides advisory technical support has been replaced with a more generic statement. Currently, the STA is required to provide advisory technical support to the Shift Supervisor. This term for whom the STA supports was derived from the generic term provided in NUREG-0737. At NMP2, both an "Assistant Station Shift Supervisor (ASSS)" and a "Station Shift Supervisor (SSS)" are on the operating shift, and both hold senior operator licenses, as required by the CTS. The USAR does not provide any clarification as to which of these two supervisors the CTS is referring, since it uses ASSS, SSS, and shift supervisor interchangeably when discussing the STA role. Normally, the STA would provide support to the ASSS, since the ASSS is normally the control room supervisor. However, when the ASSS is not in the control room, the SSS would assume the control room supervisor duties. Thus the STA could provide support to either the SSS or ASSS at the start of an event, depending upon which of the personnel was in charge of the control room. To provide a more generic, but technically accurate, statement as to whom the STA provides advisory technical support, the words "Shift Supervisor" have been replaced with "shift supervision." B

A.7 The specific STA requirements have been modified to reference the Commission Policy Statement on Engineering Expertise on Shift. Since the policy statement encompasses the current requirements, this change is considered administrative.

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

None

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 Details of the minimum shift crew requirements located in CTS Table 6.2.2-1 are proposed to be relocated to the USAR, where most of these requirements currently reside (Section 13.1). The minimum shift crew requirements for

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.1 (cont'd) licensed operators and senior operators are also contained in 10 CFR 50.54 (k), (l), and (m) and do not need to be repeated in the ITS. The minimum shift crew requirements for non-licensed plant equipment operators are transferred from CTS Table 6.2.2-1 to ITS 5.2.2.a. In addition, ITS 5.1.2 contains requirements for the control room command function, ITS 5.2.2.c contains minimum requirements for licensed Reactor Operators and Senior Operators to be present in the control room, and ITS 5.2.2.g contains STA requirements. The relocation of the details of the minimum shift crew requirements to the USAR is acceptable considering the controls provided by regulations, the remaining requirements in the ITS, and the USAR change control process (10 CFR 50.59). Therefore, the relocated requirements are not required to be in the ITS to provide adequate protection of the public health and safety.

LA.2 CTS 6.2.2.d, requires two Licensed Operators in the Control Room during reactor startup, scheduled reactor shutdown, and during recovery from reactor trips. In addition, CTS Table 6.2.2-1, including Notes (c) and (h) also requires one additional Licensed Operator during Mode 2 and one additional Assistant Station Shift Supervisor and Licensed Operator during MODES 4 and 5 when the process computer is out of operation for greater than 8 hours (note c also applies to the Station Shift Supervisor requirement, but it does not change the manning requirement currently required under normal conditions in MODES 1 through 5). These requirements are proposed to be relocated to the USAR. The requirement specifying the minimum number of operators in the control room is adequately controlled by ITS 5.2.2.b. Under the conditions specified in CTS 6.2.2.d, it is more than likely two operators will be assigned to the Control Room by the SSS due to the number of maneuvers which must be performed. The requirement for the location of these operators is also already specified in Generation Administrative Procedures. In addition, the normal operating shift includes more operators than are required by CTS Table 6.2.2-1, and during MODES 4 and 5, additional operators, above those on the normal operating shift, are also routinely available to assist in outage related activities. Therefore, the relocated requirement is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the USAR will be controlled by the provisions of 10 CFR 50.59. B B B

LA.3 CTS 6.2.2.e and 6.2.4, which specify staffing requirements during MODES 1, 2 and 3 and when the emergency plan is activated, is proposed to be relocated to the Site Emergency Plan. The requirement is that a Licensed Operator shall be required to be in the control room and this person may be either the SSS, ASSS, or another person with a valid senior operator license. When the Emergency Plan is activated and if a dedicated Shift Technical Advisor (STA) is not on shift, then the ASSS takes the role of the STA and the SSS must remain in the control room until an additional Licensed Senior Operator arrives.

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.3 (cont'd) The staffing requirements of the Emergency Plan are also documented in the Site Emergency Plan and in Generation Administrative Procedures. ITS 5.2.2.b will continue to provide the staffing requirements during MODES 1, 2, and 3 and is adequate since the personnel required during emergencies is specified. Therefore, the relocated requirement is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the Site Emergency Plan will be controlled by the provisions of 10 CFR 50.54(q).

LA.4 The Fire Protection requirements have already been relocated to the Fire Protection Plan, in accordance with Generic Letter 88-12. Therefore, the fire brigade manning requirements in CTS 6.2.2.g, including the allowance in CTS 6.2.2.g footnote * (to be below the minimum fire brigade composition requirement for a period of up to 2 hours to accommodate unexpected absence) is not needed in the Technical Specifications and is proposed to be relocated to the Fire Protection Plan. ITS 5.4.1.d maintains the requirement that written procedures be established, implemented, and maintained for Fire Protection Program implementation. Therefore, the relocated allowance is not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the requirements in the Fire Protection Plan will be controlled by the provisions of 10 CFR 50.59.

LA.5 Details contained in CTS 6.2.2.f that require all Core Alterations to be supervised by either a licensed Senior Operator or Senior Reactor Operator Limited to Fuel Handling are proposed to be relocated to the USAR. These current TS requirements are contained in 10 CFR 50.54 (m)(2)(iv) and do not need to be repeated in the ITS to provide adequate protection of the public health and safety. Once in USAR, these requirements will be under the change control provisions of 10 CFR 50.59. In addition, the details in CTS 6.2.2.f that require the fuel moves to be directly monitored by a member of the reactor analyst group is also being proposed to be relocated to the USAR.
10 CFR 50.54 (m)(2)(iv) specifies the minimum requirements for moving reactor fuel. It does not require a non-licensed member of the reactor analyst group (or any other type of engineer) to monitor the fuel movement. This is an additional administrative requirement that is not needed to be in the ITS for protection of the public health and safety. Once in the USAR, this requirement will also be under the change control provisions of 10 CFR 50.59.

LA.6 Details of the operator license requirements in CTS 6.2.2.j for these specific positions Station Shift Supervisor - Nuclear and Assistant Station Shift Supervisor Nuclear are proposed to be relocated to the USAR where they currently reside (Section 13.1). This level of detail is not necessary in the ITS to provide adequate protection of the public health and safety. These details are

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.6 (cont'd) adequately addressed by the minimum shift crew requirements in 10 CFR 50.54 (k), (l), and (m) and by the qualification requirements in ITS 5.3.1. Changes to the USAR are controlled by the provisions of 10 CFR 50.59.

LA.7 The Independent Safety Engineering Group (ISEG) requirements in CTS 6.2.3.4 are proposed to be relocated to the Appendix B of the USAR Quality Assurance Program description since they can be adequately addressed elsewhere and there is adequate regulatory authority to do so. The ISEG performs independent safety reviews. Since the ISEG provides after-the-fact recommendations to improve safety, this organization is not necessary to ensure safe operation of the facility. Therefore, inclusion of the requirements for the ISEG in ITS is not necessary to provide adequate protection of the public health and safety. Changes to Appendix B of the USAR (which implements 10 CFR 50.54 and 10 CFR 50 Appendix B) will be controlled by the provisions of 10 CFR 50.54 (a).

LA.8 CTS 6.2.1.b uses the title "Chief Nuclear Officer." In ITS 5.2.1.c this specific title is replaced with the generic term "a specified corporate officer." CTS 6.2.1.c and 6.2.2.i use the title "Plant Manager." In ITS 5.2.1.b and 5.2.2.e, this specific title is replaced with the generic title "plant manager." CTS 6.2.2.i uses the title "Vice President - Nuclear Generation." In ITS 5.2.2.e, this specific title is replaced with the generic term "a specified corporate officer." CTS 6.2.2.j uses the titles "General Supervisor Operations" and "Supervisor Operations." In ITS 5.2.2.f, these specific titles are replaced with the generic title "operations supervisors." The specific titles are proposed to be relocated to the USAR Section 13.1, which is where the organizational chart and description of these specific titles (except Supervisor Operations - only the title is provided in the USAR) is 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. The various requirements of the individuals are still retained in the ITS. In addition, the ITS also requires the organizational chart to be in the USAR. 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 USAR are controlled by the provisions of 10 CFR 50.59.

"Specific"

L.1 CTS 6.2.2.i.4 provides a description of the individuals who can be designated by the Plant Manager to approve modifications to overtime requirements. ITS 5.2.2.e will not provide this description, but will require the person to be

TECHNICAL CHANGES - LESS RESTRICTIVE

L.1 (cont'd) designated by the plant manager (changed to the generic title by Discussion of Change LA.8 above). In this way, control of who can approve this activity is still controlled by the plant manager, consistent with CTS 6.1.1 (proposed ITS 5.1.1), which states that the Plant Manager is responsible for overall unit operation. Since the plant manager is still maintaining this control, the removal of the actual person to whom the Plant Manager delegates responsibility does not impact plant safety. In addition, CTS 6.1.1 (proposed ITS 5.1.1) already allows the Plant Manager to designate an individual to take over this responsibility during the Plant Manager's absence, and this individual is not specified by title. Therefore, this change is considered acceptable.

A.1

Specification 5.5

See Discussion of Changes for ITS Section 3.0, "LCO and SR Applicability" in Section 3.0

SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements shall be met during the OPERATIONAL CONDITIONS or other conditions specified for individual Limiting Conditions for Operation unless otherwise stated in an individual Surveillance Requirement.

4.0.2 Each Surveillance Requirement shall be performed within the specified time interval with a maximum allowable extension not to exceed 25% of the surveillance interval.

4.0.3 Failure to perform a Surveillance Requirement within the allowed surveillance interval, defined by Specification 4.0.2, shall constitute noncompliance with the OPERABILITY requirements for a Limiting Condition for Operation. The time limits of the ACTION requirements are applicable at the time it is identified that a Surveillance Requirement has not been performed. The ACTION requirements may be delayed for up to 24 hours to permit the completion of the surveillance when the allowable outage time limits of the ACTION requirements are less than 24 hours. Surveillance Requirements do not have to be performed on inoperable equipment.

4.0.4 Entry into an OPERATIONAL CONDITION or other specified applicable condition shall not be made unless the Surveillance Requirement(s) associated with the Limiting Condition for Operation have been performed within the applicable surveillance interval or as otherwise specified. This provision shall not prevent passage through or to OPERATIONAL CONDITIONS as required to comply with ACTION requirements.

5.5.6 4.0.5 Surveillance Requirements for inservice ~~inspection and~~ testing of ASME Code Class 1, 2, and 3 ~~components~~ shall be applicable as follows: LA.4

a. Inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10CFR50.55a(f), except where specific written relief has been granted by the Commission pursuant to 10CFR50.55a(f)(6)(i). Inservice inspection of ASME Code Class 1, 2, and 3 components shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i). LA.5 LA.4

pumps and valves

5.5.6.a b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda for the inservice ~~inspection and~~ testing activities required by the ASME Boiler and Pressure Vessel Code and applicable addenda shall be applicable as follows in these Technical Specifications:

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Specification 5.5

add proposed Specification 5.5.7

A.13

CONTAINMENT SYSTEMS

SECONDARY CONTAINMENT

STANDBY GAS TREATMENT SYSTEM

See Discussion of Changes for ITS: 3.6.4.3, "SGT System," in Section 3.6.

SURVEILLANCE REQUIREMENTS

4.6.5.3 Each standby gas treatment subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates for at least 10 hours with the heaters OPERABLE.

5.5.7 b. At least once per ~~18~~ 24 months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings or (2) following significant painting, fire or chemical release in any ventilation zone communicating with the subsystem by: LD.2 A.18 B

1. Verifying that the subsystem satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Positions C.5.a, C.5.c, and C.5.d of RG 1.52*, Revision 2, March 1978, and ANSI N510-1980 and the subsystem flow rate is 4000 cfm ± 10%. (5.5.7.a, 5.5.7.b) A.14 LA.6

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Position C.6.b of RG 1.52*, Revision 2, March 1978, meets the laboratory testing criteria of Position C.6.a of RG 1.52*, Revision 2, March 1978, for a methyl iodide penetration of less than 0.175%; and (5.5.7.c) ASTM D3803-1979 (Method B) at a relative humidity of 95% A.14

3. Verifying a subsystem flow rate of 4000 cfm ± 10% during system operation when tested in accordance with ANSI N510-1980. (5.5.7.a,b) LA.6

5.5.7 c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Position C.6.b of RG 1.52*, Revision 2, March 1978, meets the laboratory testing criteria of Position C.6.a of RG 1.52*, Revision 2, March 1978, for a methyl iodide penetration of less than 0.175%. (5.5.7.c) ASTM D3803-1979 (Method B) at a relative humidity of 95%

A.14

* ANSI N510-1980 is applicable in place of ANSI N510-1975, and ANSI N509-1980 is applicable in place of ANSI N509-1976.

Specification 5.5

A.1

CONTAINMENT SYSTEMS

SECONDARY CONTAINMENT

STANDBY GAS TREATMENT SYSTEM

SURVEILLANCE REQUIREMENTS

4.6.5.3 (Continued) 24 LD.2

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

5.5.7.d

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 5.5 inches Water Gauge while operating the filter train at a flow rate of 4000 cfm ± 10%.

See Discussion of Changes for ITS: 3.6.4.3, in Section 3.6.

2. Verifying that the filter train starts and isolation valves open on each of the following test signals:

   a. Manual initiation from the control room, and
   b. Simulated automatic initiation signal.

3. Verifying that the decay heat removal air inlet valves are closed and can be manually opened.

A.19

5.5.7.e

4. Verifying that the heaters dissipate ~~20.8 ± 2.0 kW~~ 14.0 to 17.1 kW, adjusted to degraded voltage conditions, when tested in accordance with ANSI N510-1980.

5.5.7

5.5.7.a

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the system at a flow rate of 4000 cfm ± 10%.

A

5.5.7

5.5.7.b

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 4000 cfm ± 10%.

Specification 5.5

A.1

add proposed Specification 5.5.7 A.13

PLANT SYSTEMS

CONTROL ROOM OUTDOOR AIR SPECIAL FILTER TRAIN SYSTEM

SURVEILLANCE REQUIREMENTS

4.7.3 (Continued) 24 LD.3

c. At least once per ~~18~~ months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings or (2) following painting, fire, or chemical release in any ventilation zone communicating with the filter trains by: A.18 Significant B

5.5.7

1. Verifying that the filter train satisfies the in-place penetration and bypass testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Positions C.5.a, C.5.c, and C.5.d of RG 1.52*, Revision 2, March 1978, and the system flow rate is 2250 cfm ± 10%. and ANSI N510-1980 A.14

5.5.7.a
5.5.7.b

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Position C.6.b of RG 1.52*, Revision 2, March 1978, meets the laboratory testing criteria of Position C.6.a of RG 1.52*, Revision 2, March 1978, for a methyl iodide penetration of less than 0.175%; and at a relative humidity of 95% LA.6 ASTM D3803 1979 (Method B) A.14

5.5.7.c

5.5.7.a,b

3. Verifying a subsystem flow rate of 2250 cfm ± 10% during subsystem operation when tested in accordance with ANSI N510-1980. LA.6

5.5.7

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Position C.6.b of RG 1.52*, Revision 2, March 1978, meets the laboratory testing criteria of Position C.6.a of RG 1.52*, Revision 2, March 1978, for a methyl iodide penetration of less than 0.175% at a relative humidity of 95% ASTM D3803-1979 (Method B) A.14

5.5.7.c

e. At least once per ~~18~~ months by: 24 LD.3

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 5.5 inches water gauge (WG) while operating the subsystem at a flow rate of 2250 cfm ± 10%.

5.5.7.d

2. Verifying that on each of the below pressurization mode actuation test signals, the filter train automatically switches to the emergency pressurization mode of operation and the control room is maintained at a positive pressure of 1/8 inch WG relative to the outside atmosphere during subsystem operation at an outside air intake flow rate less than or equal to 1500 cfm.

(a) Air intake radiation monitors, and

(b) LOCA, and

See Discussion of Changes for ITS: 3.7.3, "Control Room Envelope Filtration (CREF) System," in Section 3.7.

* ANSI N510-1980 is applicable in place of ANSI N510-1975, and ANSI N509-1980 is applicable in place of ANSI N509-1976. A.14

Specification 5.5

A.1

PLANT SYSTEMS

CONTROL ROOM OUTDOOR AIR SPECIAL FILTER TRAIN SYSTEM

SURVEILLANCE REQUIREMENTS

A.19

4.7.3.e (Continued)

5.5.7.e 3. Verifying that the heaters dissipate 7.95 kW or more, adjusted to degraded voltage conditions, when tested in accordance with ANSI N510-1980.

5.5.7 f. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 while operating the system at a flow rate of 2250 cfm ± 10%.

5.5.7.a

B

5.5.7 g. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 2250 cfm ± 10%.

5.5.7.b

A.1

Specification 5.5

TABLE 5.7.1-1

REACTOR CYCLIC OR TRANSIENT LIMITS AND DESIGN CYCLE OR TRANSIENT

LA.8

CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
120 heatup and cooldown cycles	70°F to 565°F to 70°F
80 step change cycles	Loss of feedwater heaters
198 reactor trip cycles	100% to 0% of RATED THERMAL POWER
130 hydrostatic and system leakage tests	Pressurized to ≥930 psig and ≤1250 psig

B

ADMINISTRATIVE (continued)

A.16 Not used. 16

A.17 Not used. 16

A.18 CTS 4.6.5.3.b and 4.7.3.c require certain SGT and CREF System filter testing following painting, fire, or chemical release in any ventilation zone communicating with the filter trains. ITS 5.5.7 only requires testing if the painting, fire, or chemical release is significant. Current NMP2 practice is that not all painting, fire, or chemical release results in the need to perform certain ventilation tests. Only painting, fire, or chemical release that could affect the ventilation filter trains, i.e., that which is significant would require performance of the tests. The word "significant" was added for clarity and consistency with current practice to avoid a misinterpretation that any painting, fire, or chemical release (such as using a small can of paint to do touch-up work in the reactor building) would result in the need to perform the tests. This clarification is administrative, and is consistent with the most recently approved BWR/5 ITS amendment, WNP-2. In addition, the NRC, in a letter to Entergy Operations, Inc., dated September 11, 1997, supported the clarification that not all painting, fires, or chemical releases required the filter trains to be tested. B

A.19 CTS 4.6.5.3.d.4 requires the SGT System heaters to dissipate 20.0 ± 2.0 kW and CTS 4.7.3.e.3 requires the CREF System heaters to dissipate ≥ 7.95 kW. However, no voltage conditions to which the heaters are normalized are specified. The accident analysis assumes the degraded voltage condition, therefore, ITS 5.5.7.e will specify the heaters must dissipate the required kW at degraded voltage conditions. The current heater value for the CREF System (≥ 7.95 kW) is already normalized to degraded voltage conditions. However, the SGT System value is at nominal conditions (i.e. 480 V). Therefore, the value of 20.0 ± 2.0 kW (i.e. 18 kW to 22 kW) is being changed to the proper value when normalized to degraded voltage conditions, i.e., 14.0 kW to 17.1 kW. Since this change is only a presentation preference and the requirements are not changing, this change is considered administrative. B

RELOCATED SPECIFICATIONS

None

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 Two new programs are included in the proposed Technical Specifications. These programs are:

ITS 5.5.10	Technical Specification (TS) Bases Control
ITS 5.5.11	Safety Function Determination Program (SFDP)

The TS Bases Control Program is provided to specifically delineate the appropriate methods and reviews necessary for a change to the Technical Specification Bases. The Safety Function Determination Program is included to support implementation of the support system OPERABILITY characteristics of the Technical Specifications. The specific wording associated with these two programs may be found in ITS 5.5.10 and 5.5.11.

M.2 Expanded requirements for the ODCM are included in the proposed ITS 5.5.1. These requirements identify monitoring activities and report requirements, and establish content and format for documenting licensee-initiated changes. These are consistent with Generic Letter 89-01, and are additional restrictions on plant operations.

TECHNICAL CHANGES - LESS RESTRICTIVE

"Generic"

LA.1 The details contained in CTS 6.8.4.b, "In-Plant Radiation Monitoring," are proposed to be relocated to the USAR, where it currently resides (USAR, Chapter 12). This program is required by the NMP2 commitment to NUREG-0737, Item III.D.3.3 as stated in the USAR, Section 1.10. This program contains controls to ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program is designed to minimize radiation exposure to plant personnel post-accident and has no impact on nuclear safety or the health and safety of the public. The training aspect of the program is accomplished as part of the continual training program for personnel in the cognizant organizations, as well as during the training for those individuals responsible for implementing the Radiological Emergency Planning procedures. Provisions for monitoring and performing maintenance of the sampling and analysis equipment are addressed in chemistry and radiation protection procedures. 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 USAR are controlled by the provisions of 10 CFR 50.59.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

LA.2 The details contained in CTS 6.8.4.d, "Fire Protection Program," are proposed to be relocated to the USAR, where it currently resides (USAR, Appendix 9A). This program is required by an NMP2 commitment to Branch Technical Position APCSB 9.5-1 Appendix A, as stated in USAR, Appendix B. ITS 5.4.1.d will continue to require that procedures shall be established to implement and maintain the Fire Protection Program. This is consistent with Generic Letter 88-12, which allowed the Fire Protection Program requirements to be relocated to plant controlled documents. 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 USAR are controlled by the provisions of 10 CFR 50.59.

LA.3 The CTS 6.14.2.a.3 and 6.14.2.b requirements that the ODCM must be reviewed and accepted by the Station Operations Review Committee (SORC) prior to implementation and to document this review and acceptance are proposed to be relocated to Appendix B of the USAR (Quality Assurance Program description). The details of the SORC responsibilities currently resides in Section 13.4 of the USAR. A cross reference to Section 13.4 of the USAR is proposed to be made in Appendix B of the USAR so that changes to the relocated requirement will be made in accordance to the same requirements of Appendix B. The review activities performed by the SORC are required by ANSI N18.7-1976. Thus, the provisions are not necessary to be included in the ITS to provide adequate protection of the public health and safety, given the existence of these redundant requirements. Changes to Appendix B in the USAR will be controlled by the provisions of 10 CFR 50.54(a).

LA.4 Details of the Inservice Inspection (ISI) Program in CTS 4.0.5 are proposed to be relocated to the plant controlled ISI Program. The ISI Program is required by 10 CFR 50.55a to be performed in accordance with ASME Section XI. Compliance with 10 CFR 50.55a is required by the NMP2 Operating License. The NMP2 ISI Program, outside of the CTS, implements the applicable provisions of ASME Section XI. Generic Letter 88-01 provides an ISI Program for piping in accordance with the NRC staff positions on schedule, methods, personnel, and sample expansion or in accordance with alternate measures approved by the NRC staff. NMP2 commitments to Generic Letter 88-01 are documented to the NRC in a letter dated July 28, 1988, and do not need to be repeated in the ITS. Regulations and NMP2 commitments to the NRC contain the necessary programmatic requirements for ISI without repeating them in the ITS. 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 plant controlled ISI Program will be controlled by the provisions of 10 CFR 50.55a. In addition, since the Inservice Testing Program is the only requirement remaining, the reference to ASME Code Class 1, 2,

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.4 (cont'd) and 3 "components" has been changed to "pumps and valves" for clarity. Pumps and valves are the only components related to the Inservice Testing Program (as described in CTS 4.0.5.a).

LA.5 Details of the Inservice Testing Program (IST) in the CTS 4.0.5 are proposed to be relocated to the plant controlled IST Program. The relocated requirements are duplicated in 10 CFR 50.55a, which requires the implementation of ASME, Section XI and applicable addenda, for inservice testing of ASME Code Class 1, 2, and 3 pumps and valves. Compliance with 10 CFR 50.55a is required by the NMP2 Operating License. Therefore, it is not necessary to retain the details proposed to be relocated in the ITS, since these details are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the plant controlled IST program will be controlled by the provisions of 10 CFR 50.55a.

LA.6 Details of the methods for implementing CTS 4.6.5.3.b.2, 4.6.5.3.c, 4.7.3.c.2, and 4.7.3.d are relocated to the Technical Requirements Manual (TRM). The requirements of ITS 5.5.7 are adequate to ensure the required ventilation filter testing is performed. Proposed SR 3.6.4.3.2 of ITS 3.6.4.3, "Standby Gas Treatment (SGT) System," which requires ventilation filter testing of the SGT System to be performed in accordance with the VFTP, and proposed SR 3.7.3.2 of ITS 3.7.3, "Control Room Envelope Filtration (CREF) System", which requires ventilation filter testing of the CREF System to be performed in accordance with the VFTP, and the requirements of ITS 5.5.7 provide adequate regulatory controls over the testing requirements proposed to be relocated. As a result, the requirements proposed to be relocated are not required to be included in the Technical Specifications to ensure required ventilation filter testing is adequately performed. Therefore, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. The TRM will be incorporated by reference into the NMP2 USAR at ITS implementation. Changes to the TRM will be controlled by the provisions of 10 CFR 50.59.

LA.7 The details for implementing the requirements contained in CTS 3/4.11.1.4 and CTS 3/4.11.2.6 are proposed to be relocated to the Technical Requirements Manual (TRM). The requirements of ITS 5.5.8 are adequate to ensure the quantity of radioactivity in outside liquid storage tanks is maintained within limits and explosive gas mixtures in the main condenser offgas treatment system are maintained within limits. ITS 5.5.8 provides regulatory control over the limitations and surveillances proposed to be relocated. The details proposed to be relocated are not required to be included in the ITS to ensure the quantity of radioactivity in outside liquid storage tanks is maintained within limits and explosive gas mixtures in the main condenser offgas treatment system are

TECHNICAL CHANGES - LESS RESTRICTIVE

LA.7 (cont'd) maintained within limits. Therefore, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. The TRM will be incorporated by reference into the NMP2 USAR at ITS implementation. Changes to the TRM will be controlled by the provisions of 10 CFR 50.59.

LA.8 Details of the components governed by CTS 5.7 (Component Cyclic or Transient Limit) are proposed to be relocated to the USAR. The requirement to monitor the cyclic and transient occurrences is maintained as a program in ITS 5.5.5 (Component Cyclic or Transient Limit). ITS 5.5.5 provides adequate regulatory control over the details to be relocated. As a result, the relocated details are not required to be in the ITS to provide adequate protection of the public health and safety. Changes to the USAR are controlled by the provisions of 10 CFR 50.59.

LA.9 CTS 6.5.2.11 uses the title "Plant Manager." In ITS 5.5.1.c.2, this specific title is replaced with the generic title "plant manager." The specific title is proposed to be relocated to the USAR Section 13.1, which is where the organizational chart and 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 plant manager are still retained in the ITS. In addition, the ITS also requires the organizational chart to be in the USAR. 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 USAR are controlled by the provisions of 10 CFR 50.59.

LD.1 The Frequency for performing CTS 6.8.4.a.2 (ITS 5.5.2.b) has been extended from 18 months to 24 months. This requirement establishes a program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. 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 4.0.2 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 4.0.2 and proposed SR 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. Reviews of historical maintenance and surveillance data have shown that this test normally passes the Surveillance at the current Frequency. An evaluation has been

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.1 (cont'd) performed using this data, and it has been determined that the effect on safety due to the extended Surveillance Frequency will be small. This conclusion is based upon the fact that most portions of the subject systems included in this program are visually walked down, while the plant is operating, during plant testing, and/or operator/system engineer walkdowns. In addition, housekeeping/safety walkdowns also serve to detect any gross leakage. If leakage is observed from these systems, corrective actions will be taken to repair the leakage. Finally, the plant Health Physics radiological surveys will also identify any potential sources of leakage. These visual walkdowns and surveys provide monitoring of the systems at a greater frequency that once per refueling cycle, and support the conclusion that the impact, if any, on safety is small as a result of the proposed changes.

The review of historical maintenance and surveillance data also demonstrates that there is no adverse trend that would invalidate the conclusion that the impact on system availability, if any, is small from a change to CTS 6.8.4.a.2 as implemented in ITS 5.5.2.b. In addition, the proposed 24 month Surveillance Frequency, if performed at the maximum interval allowed by proposed SR 3.0.2 (30 months) does not invalidate any assumptions in the plant licensing basis.

LD.2 The Frequency for performing CTS 4.6.5.3.b.1, 4.6.5.3.b.2, 4.6.5.3.b.3, 4.6.5.3.d.1, and 4.6.5.3.d.4 has been extended from 18 months to 24 months in ITS 5.5.7. These requirements ensure that the SGT System inplace charcoal adsorbers, HEPA filters, and heaters perform their safety function. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 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. 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 small. USAR Section 6.5.1.4 identifies that charcoal adsorber and HEPA filter in-place tests are in accordance with Regulatory Guide 1.52, which states that testing Frequencies be at least once per 18 months. The SGT System filters radioactive particulates and both radioactive and nonradioactive forms of iodine from the air exhausted from the reactor enclosure and/or refueling area to maintain a negative pressure

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.2 (cont'd) during secondary containment isolation. Regulatory positions C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, state HEPA filters and carbon adsorbers should be in-place tested (1) initially, (2) at least once per 18 months thereafter, and (3) following painting, fire, or chemical release in any ventilation zone communicating with the system. Position C.5.d also states that carbon adsorbers should be in-place tested following removal of an adsorber sample for laboratory testing if the integrity of the adsorber section is affected. ITS 5.5.7 also requires in-place filter and charcoal adsorber testing and filter pressure drop testing after any structural maintenance on the HEPA filter or charcoal adsorber housings or following painting, fire, or chemical release in any ventilation zone communicating with the SGT System. By testing after maintenance, fire, chemical release, painting, HEPA replacement, or charcoal replacement, potential changes in HEPA filter efficiency, carbon adsorber bypass leakage, and filter pressure drop will be detected that would be detected by conducting the 18 month surveillance tests. The SGT System is normally in standby. In addition, the SGT System active components and power supplies are designed with redundancy to meet the single active failure criteria, which will ensure system availability in the event of a failure of one of the system components. Based on the fact that the SGT System is normally in standby and additional testing will be performed if potential degradation occurs and the system design, it is shown that the impact, if any, on system availability is small as a result of this change.

The review of historical maintenance and surveillance data also demonstrates that there are no failures that would invalidate the conclusion that the impact on system availability, if any, is small from a change to CTS 4.6.5.3.b.1, 4.6.5.3.b.2, 4.6.5.3.b.3, 4.6.5.3.d.1, and 4.6.5.3.d.4 as implemented in ITS 5.5.7, 5.5.7.a, 5.5.7.b, 5.5.7.c, 5.5.7.d, and 5.5.7.e. 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.

LD.3 The Frequency for performing CTS 4.7.3.c.1, 4.7.3.c.2, 4.7.3.c.3, 4.7.3.e.1, and 4.7.3.e.3 has been extended from 18 months to 24 months in ITS 5.5.7. These requirements ensure that in-place Control Room Envelope Filtration System charcoal adsorbers, HEPA filters, and heaters are capable of performing their safety function. The proposed change will allow these Surveillances to extend their 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 4.0.2 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 4.0.2 and proposed SR 3.0.2). This proposed change was evaluated in accordance with the guidance provided

TECHNICAL CHANGES - LESS RESTRICTIVE

LD.3 (cont'd) in NRC Generic Letter No. 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991. 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 small. Table 1.8-1 (Conformance with Division I NRC Regulatory Guides) and Section 9.4.1.2.2 of the USAR identifies that charcoal adsorber and HEPA filter in-place tests are in accordance with Regulatory Guide 1.52, which states that testing Frequencies be every 18 months. The Control Room Envelope Filtration (CREF) System provides filtration for control room air intake and recirculated air during a high radiation accident and maintains a positive pressure in the control room during control room isolation. Regulatory positions C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, require CREF System filters and charcoal adsorbers be in-place tested (1) initially, (2) at least once per 18 months thereafter, and (3) following painting, fire, or chemical release in any ventilation zone communicating with the system. Position C.5.d also states that carbon adsorbers should be in-place tested following removal of an adsorber sample for laboratory testing if the integrity of the adsorber section is affected. ITS 5.5.7 also requires in-place filter and charcoal adsorber testing and filter pressure drop testing after any structural maintenance on the HEPA filter or charcoal adsorber housings or following painting, fire, or chemical release in any ventilation zone communicating with the CREF System. By testing after maintenance, fire, chemical release, painting, HEPA replacement, or charcoal replacement, potential changes in HEPA filter efficiency, carbon adsorber bypass leakage, and filter pressure drop will be detected that would be detected by conducting the 18 month surveillance tests. The CREF System is normally in standby. In addition, the CREF System active components and power supplies are designed with redundancy to meet the single active failure criteria, which will ensure system availability in the event of a failure of one of the system components. Based on the fact that the CREF System is normally in standby and additional testing will be performed if potential degradation occurs and the system design, it is shown that the impact, if any, on system availability is small as a result of this change.

The review of historical maintenance and surveillance data also demonstrates that there are no failures that would invalidate the conclusion that the impact on system availability, if any, is small from a change to CTS 4.7.3.c.1, 4.7.3.c.2, 4.7.3.c.3, 4.7.3.e.1, and 4.7.3.e.3 as implemented in ITS 5.5.7, 5.5.7.a, 5.5.7.b, 5.5.7.c, 5.5.7.d, and 5.5.7.e. 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.

TECHNICAL CHANGES - LESS RESTRICTIVE (continued)

"Specific"

None

<CTS>

5.2 Organization

5.2.2 Unit Staff (continued)

<6.2.2.h>
<6.2.2.i>

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time;

2. An individual should not be permitted to work more than 16 hours in any 24 hour period, nor more than 24 hours in any 48 hour period, nor more than 72 hours in any 7 day period, all excluding shift turnover time;

3. A break of at least 8 hours should be allowed between work periods, including shift turnover time; and

4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized in advance by the Plant Superintendent or his designee, in accordance with approved administrative procedures, or by higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation.

manager
TSTF-65

Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the Plant Superintendent or his designee to ensure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized.

TSTF-65
manager
TSTF-65
a specified corporate officer

OR

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).

f. The Operations Manager or Assistant Operations Manager shall hold an SRO license.

<6.2.2.j>

operations supervisors

<6.2.4> g. The Shift Technical Advisor (STA) shall provide advisory technical support to the Shift Supervisor (SS) 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.

TSTF-65 (lower case change)

shift supervision

JUSTIFICATION FOR DEVIATIONS FROM NUREG-1434, 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. Since NMP2 is a single unit, the Equipment Operator requirements have been revised for clarity. Also, the bracketed information regarding dual unit sites has been deleted.

4. The referenced requirement is a Specification, not a CFR requirement. Therefore, the word "Specification" has been added to clearly state that "5.5.2.a" is a Specification. In addition. Specification 5.5.2.g has been deleted since it only describes the STA qualifications, not that an STA is part of the shift crew composition and when the STA is required (i.e., MODES 1, 2, and 3).

5. These words have been added to ITS 5.5.2.d for consistency with a similar statement in ITS 5.5.2.c and the current licensing basis.

6. The STA provides advisory technical support to all members of the shift crew, including the Station Shift Supervisor and Assistant Station Shift Supervisor (i.e., the NUREG Shift Supervisor position). In addition, the STA position could be filled by the ASSS (provided the ASSS meets the appropriate requirements). To preclude confusion that could arise when the STA position is filled by the ASSS (e.g., can the STA provide advice to himself/herself as the ASSS), the statement as to who the STA provides advice to has been modified to use the generic term "shift supervision." (B)

7. The proper plant specific department description has been provided in ITS 5.2.1.d and 5.2.2.e.

<CTS>

5.5 Programs and Manuals

<DOC A.3> 5.5.4 Radioactive Effluent Controls Program (continued)

the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

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

6

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to ~~10 CFR 20,~~ Appendix B, Table 2, Column 2; to 10 CFR 20.1001-20.2402 B

ten times the concentration values in

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

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

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

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I; 21 B

6

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas beyond the site boundary ~~conforming to the dose associated with 10 CFR 20, Appendix B, Table 2, Column 1;~~ ator

<Insert 5.5.4.g>

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each

(continued)

shall be in accordance with the following:

1. For noble gases: a dose rate ≤ 500 mrems/yr to the whole body and a dose rate ≤ 3000 mrems/yr to the skin, and

2. For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives greater than 8 days: a dose rate ≤ 1500 mrems/yr to any organ;

<CTS>

k. Limitations on venting and purging of the primary containment through the Standby Gas Treatment System to maintain releases as low as reasonably achievable.

7

5.5 Programs and Manuals

<Doc A.3>

23

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Radioactive Effluent Control Program surveillance frequencies.

5.5.4 Radioactive Effluent Controls Program (continued)

unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and 7

j. Limitations on the annual beyond the site boundary, dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190; and 7 21 B

<5.7>

5.5.5 Component Cyclic or Transient Limit

8 U Table 3.9B-1a 2

This program provides controls to track the UFSAR, Section [ ], Note 5 cyclic and transient occurrences to ensure that components are maintained within the design limits.

9

5.5.6 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containments, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. The program shall include baseline measurements prior to initial operations. The Tendon Surveillance Program, inspection frequencies, and acceptance criteria shall be in accordance with [Regulatory Guide 1.35, Revision 3, 1989].

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Tendon Surveillance Program inspection frequencies.

5.5 6 9 Inservice Testing Program

<4.0.5>
<4.0.5.a>

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 pumps and valves components including applicable supports. The 10 program shall include the following: 10

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(continued)

<CTS>

5.5 Programs and Manuals

5.5.~~8a~~ 7 9 Ventilation Filter Testing Program (VFTP) (continued)

<4.6.5.3.d.1>
<4.7.3.e.1>

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters ~~the prefilters~~ and the charcoal adsorbers is less than the value specified below when tested ~~in accordance with [Regulatory Guide 1.52, Revision 2, and ASME N510-1989]~~ at the system flowrate specified below ~~[± 10%]~~: 15 2

ESF Ventilation System	Delta P (inches wg)	Flowrate (cfm)
SGT System	<5.5	3600 to 4400
CREF System	<5.5	2025 to 2475

2 2 8 8

<4.6.5.3.d.4>
<4.7.3.e.3>

e. Demonstrate that the heaters for each of the ESF systems dissipate the value specified below ~~[± 10%]~~ when tested in accordance with ~~ASME~~ ANSI ~~N510-1989~~: 2 adjusted to degraded voltage conditions. 0 2

ESF Ventilation System	Wattage (kW)
SGT System	14.0 to 17.1
CREF System	≥ 7.95

2 8 B

12 MOVE THIS INSERT 5.5.7-B TO PAGE 5.0-11

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

<DOC A.15> 5.5.~~8b~~ 8 9 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the ~~[Waste Gas Holdup System], [the quantity of radioactivity contained in gas storage tanks or fed into the offgas treatment system,~~ and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks~~.~~ ~~The gaseous radioactivity quantities shall be determined following the methodology in [Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure"]. The liquid radwaste quantities shall be determined in accordance with [Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures"].~~ 2 16

2 Main Condenser Offgas Treatment System

(continued)

16. (continued)

Surveillance Program (ITS 5.5.8.b). Therefore, the sentence in the introductory paragraph is not necessary to specify a method to determine liquid radwaste quantities.

17. The requirement to limit oxygen in the Main Condenser Offgas Treatment System has been deleted consistent with current licensing basis.

18. These provisions in ISTS 5.5.9.b are only for the PWRs and are not applicable for NMP2. Due to this deletion, the following Specification has been renumbered.

19. The limit for the quantity of radioactivity in unprotected outdoor liquid storage tanks has been changed to be consistent with the current licensing basis limit.

20. The following changes have been made to ISTS 5.5.10:

    a. The allowance to perform a specific gravity determination has been added to ISTS 5.5.10.a.1, consistent with current licensing basis (as described in the current Bases for LCO 3.8.1, which were approved by the NRC in Amendment 70).

    b. The requirement to verify proper color in ISTS 5.5.10.a.3 has been deleted, consistent with current licensing basis (also approved in Amendment 70).

    c. The type of fuel oil, Type 2D, has been deleted consistent with current licensing basis.

    d. The term "sampling and" in ISTS 5.5.9.b has been deleted to avoid confusion as to when the 31 days starts. This is consistent with current licensing basis (also approved in Amendment 70).

    e. The words in ISTS 5.5.10.c "Method A-2 or A-3" have been changed to "Method A" in ITS 5.5.9.c to be consistent with current licensing basis. This is also consistent with TSTF-120.

21. These words have been added for clarity.

22. The 10 CFR 50 Appendix J Testing Program has been added to be consistent with the current licensing basis and TSTF-52.

23. These requirements in ITS 5.5.4 are currently located in individual Specifications in the CTS. Thus, CTS 4.0.2 (ITS SR 3.0.2) and CTS 4.0.3 (ITS SR 3.0.3) apply to the CTS surveillance frequencies. To maintain consistency with the current licensing basis requirements, an allowance that SR 3.0.2 and SR 3.0.3 are applicable to the surveillance frequencies has been added to ITS 5.5.4. This change is consistent with

23 (continued)

TSTF-258, Rev. 3, except that in the NMP2 submittal, the words are "surveillance frequencies" in lieu of "surveillance frequency" since the surveillance tests required by ITS 5.5.4 are not all performed at the same frequency. B