WOLF CREEK
NUCLEAR OPERATING CORPORATION

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RA 10-0026

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

Subject: Docket No. 50-482: Wolf Creek Generating Station Changes to Technical Specification Bases – Revisions 41 through 44

Gentlemen:

The Wolf Creek Generating Station (WCGS) Unit 1 Technical Specifications (TS), Section 5.5.14, "Technical Specifications (TS) Bases Control Program," provide the means for making changes to the Bases without prior NRC approval. In addition, TS Section 5.5.14 requires that changes made without NRC approval be provided to the NRC on a frequency consistent with 10 CFR 50.71(e). The Enclosure provides those changes made to the WCGS TS Bases (Revisions 41 through 44) under the provisions of TS Section 5.5.14 and a List of Effective Pages. This submittal reflects changes from January 1, 2009 through December 31, 2009.

This letter contains no commitments. If you have any questions concerning this matter, please contact me at (620) 364-4117.

Sincerely,

Richard D. Flannigan

RDF/rlt

Enclosure

cc: E. E. Collins (NRC), w/e
G. B. Miller (NRC), w/e
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A001

Enclosure to RA 10-0026

Wolf Creek Generating Station

Changes to the Technical Specification Bases
(50 pages)

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and Anticipated Operational Occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak Linear Heat Rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

BASES

LCO 3.0.6 (continued)

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception LCO 3.1.8 allows specified Technical Specification (TS) requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

LCO 3.0.8

LCO 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This LCO states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

BASES

LCO 3.0.8 (continued)

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

LCO 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. LCO 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

LCO 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. LCO 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

LCO 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (the Maintenance Rule) does not address seismic risk. However, use of LCO 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

BASES

ACTIONS

A.1.2.1 and A.1.2.2 (continued)

A.1.2.1 is consistent with those allowed for in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing the plant to remain in an unacceptable condition for an extended period of time. The Completion Times of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints.

A.2

Once the power level has been reduced to ≤ 50% RTP per Required Action A.1.2.1, an incore flux map (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 68 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 72 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 72 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore flux map, perform the required calculations, and evaluate $F^N_{\Delta H}$.

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is identified, to the extent necessary, and corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

BASES

ACTIONS (continued)

B.1

When Required Actions A.1.1 through A.3 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

SR 3.2.2.1 is modified by a Note. The Note applies during power ascensions following a plant shutdown (leaving Mode 1). The Note allows for power ascensions if the surveillances are not current. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. Equilibrium conditions are achieved when the core is sufficiently stable at the intended operating conditions to perform flux mapping.

The value of $F^N_{\Delta H}$ is determined by using the movable incore detector system to obtain a flux distribution map. A calculation determines the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. The measured value of $F^N_{\Delta H}$ must be increased by 4% to account for measurement uncertainty before making comparisons to the $F^N_{\Delta H}$ limit.

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

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

REFERENCES

1. USAR, Section 15.4.8.

2. 10 CFR 50, Appendix A, GDC 26.

3. 10 CFR 50.46.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.4 (continued)

large enough to demonstrate signal path continuity. This test is performed every 92 days on a STAGGERED TEST BASIS. The time allowed for the testing (4 hours) is justified in Reference 7. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 13.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a COT.

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

The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The Frequency of 184 days is justified in Reference 13.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation MODE is prevented from operation by the slave relay blocking circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This test is performed every 18 months. This Frequency is based on relay reliability assessments presented in WCAP-13878-P-A, "Reliability Assessment of Potter & Brumfield MDR Series Relays," (Ref. 9). The reliability assessments are relay specific and apply only to Potter & Brumfield MDR series relays.

For Function 4.c (Steam Line Isolation – Automatic Actuation Logic (MSFIS)) and Function 5.b (Turbine Trip and Feedwater Isolation – Automatic Actuation Logic (MSFIS)), SR 3.3.2.6 is performed on the associated slave relays in the SSPS cabinets and includes verification that the slave relays are energized at the MSFIS cabinets.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT every 18 months. This test is a check of the Loss of Offsite Power function. The trip actuating devices tested within the scope of SR 3.3.2.7 are the LSELS output relays and BOP ESFAS separation groups logic associated with the auto-start of the turbine driven AFW pump upon an ESF bus undervoltage condition.

The SR is modified by a Note that excludes verification of setpoints for relays. The Frequency is adequate. It is based on industry operating experience, considering instrument reliability and operating history data and is consistent with the typical refueling cycle. The trip actuating devices tested have no associated setpoint.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a TADOT. This test is a check of the Manual Actuation Functions (SSPS) and AFW pump start on trip of all MFW pumps BOP ESFAS. The Manual Safety Injection TADOT shall independently verify OPERABILITY of the handswitch undervoltage and shunt trip contacts for both the Reactor Trip Breakers and Reactor Trip Bypass Breakers as well as the contacts for safety injection actuation. It is performed every 18 months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

SR 3.3.2.9

SR 3.3.2.9 is the performance of a CHANNEL CALIBRATION.

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

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.10 (continued)

response time, is included in the testing of each channel. The final actuation device in one train is tested with each channel. Therefore, staggered testing results in response time verification of these devices every 18 months. The 18 month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

This SR is modified by a Note that clarifies that the turbine driven AFW pump is tested within 24 hours after reaching 900 psig in the SGs.

SR 3.3.2.11

SR 3.3.2.11 is the performance of a TADOT as described in SR 3.3.2.8, except that it is performed for the P-4 Reactor Trip Interlock, and the Frequency is every 18 months. This Frequency is based on operating experience.

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Function tested has no associated setpoint. This TADOT does not include the circuitry associated with steam dump operation since it is control grade circuitry.

SR 3.3.2.12

SR 3.3.2.12 is the performance of a monthly COT on ESFAS Function 6.h, "Auxiliary Feedwater Pump Suction Transfer on Suction Pressure - Low."

A COT is performed to ensure the channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1.

The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

BASES

REFERENCES

1. USAR, Chapter 6.

2. USAR, Chapter 7.

3. USAR, Chapter 15.

4. IEEE-279-1971.

5. 10 CFR 50.49.

6. WCNOC Nuclear Safety Analysis Setpoint Methodology for the Reactor Protection System, TR-89-0001.

7. WCAP-10271-P-A Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," June 1990.

8. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.

9. WCAP-13878-P-A, Revision 2, "Reliability Assessment of Potter & Brumfield MDR Series Relays," August 2000.

10. "Wolf Creek Setpoint Methodology Report," SNP (KG)-492, August 29, 1984.

11. Amendment No. 43 to Facility Operating License No. NPF-42, March 29, 1991.

12. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.

13. WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2003.

14. 10 CFR 50.55a(b)(3)(iii), Code Case OMN-1.

15. Performance Improvement Request (PIR) 2005-2067.

TABLE B 3.3.2-1
(Page 1 of 2)

FUNCTION	TRIP SETPOINT[a]
1. Safety Injection	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Containment Pressure – High-1	≤ 3.5 psig
d. Pressurizer Pressure - Low	≥ 1830 psig
e. Steam Line Pressure - Low	≥ 615 psig
2. Containment Spray	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Containment Pressure - High-3	≤ 27.0 psig
3. Containment Isolation	
a. Phase A Isolation	
(1) Manual Initiation	N.A.
(2) Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
(3) Safety Injection	See Function 1 (Safety Injection)
b. Phase B Isolation	
(1) Manual Initiation	N.A.
(2) Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
(3) Containment Pressure - High-3	≤ 27.0 psig
4. Steam Line Isolation	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Automatic Actuation Logic (MSFIS)	N.A.
d. Containment Pressure - High-2	≤ 17.0 psig
e. Steam Line Pressure	
(1) Low	≥ 615 psig
(2) Negative Rate - High	≤ 100 psi

TABLE B 3.3.2-1
(Page 2 of 2)

FUNCTION	TRIP SETPOINT[(a)]
5. Turbine Trip and Feedwater Isolation	
a. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
b. Automatic Actuation Logic (MSFIS)	N.A.
c. SG Water Level - High High	≤ 78% of narrow range instrument span
d. Safety Injection	See Function 1 (Safety Injection)
6. Auxiliary Feedwater	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Automatic Actuation Logic and Actuation Relays (BOP ESFAS)	N.A.
d. SG Water Level - Low-Low	≥ 23.5% of narrow range instrument span
e. Safety Injection	See Function 1 (Safety Injection)
f. Loss of Offsite Power	N.A.
g. Trip of all Main Feedwater Pumps	N.A.
h. Auxiliary Feedwater Pump Suction Transfer on Suction Pressure - Low	≥ 21.60 psia
7. Automatic Switchover to Containment Sump	
a. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
b. Refueling Water Storage Tank (RWST) Level - Low Low	≥ 36% of instrument span
Coincident with Safety Injection	See Function 1 (Safety Injection)
8. ESFAS Interlocks	
a. Reactor Trip, P-4	N.A.
b. Pressurizer Pressure, P-11	≤ 1970 psig

(a) The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value.

Table B 3.3.2-2
(Page 1 of 3)

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual Initiation	
a. Safety Injection (ECCS)	N.A.
b. Containment Spray	N.A.
c. Phase "A" Isolation	N.A.
d. Phase "B" Isolation	N.A.
e. Containment Purge Isolation	N.A.
f. Steam Line Isolation	N.A.
g. Feedwater Isolation	N.A.
h. Auxiliary Feedwater	N.A.
I. Essential Service Water	N.A.
j Containment Cooling	N.A.
k. Control Room Isolation	N.A.
l. Reactor Trip	N.A.
m. Emergency Diesel Generators	N.A.
n. Component Cooling Water	N.A.
o. Turbine Trip	N.A.
2. Containment Pressure - High-1	
a. Safety Injection (ECCS)	≤ 29(7)/27(4)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 2(5)
3) Phase "A" Isolation	≤ 1.5(5)
4) Auxiliary Feedwater	≤ 60
5) Essential Service Water	≤ 60(1)
6) Containment Cooling	≤ 60(1)
7) Component Cooling Water	N.A.
8) Emergency Diesel Generators	≤ 14(6)
9) Turbine Trip	N.A.
3. Pressurizer Pressure - Low	
a. Safety Injection (ECCS)	≤ 29(7)/27(4)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 2(5)
3) Phase "A" Isolation	≤ 2(5)
4) Auxiliary Feedwater	≤ 60
5) Essential Service Water	≤ 60(1)
6) Containment Cooling	≤ 60(1)
7) Component Cooling Water	N.A.
8) Emergency Diesel Generators	≤ 14(6)
9) Turbine Trip	N.A.

Table B 3.3.2-2
(Page 2 of 3)

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
4. Steam Line Pressure - Low	
a. Safety Injection (ECCS)	≤ 39(3)/27(4)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 2(5)
3) Phase "A" Isolation	≤ 2(5)
4) Auxiliary Feedwater	≤ 60
5) Essential Service Water	≤ 60(1)
6) Containment Cooling	≤ 60(1)
7) Component Cooling Water	N.A.
8) Emergency Diesel Generators	≤ 14(6)
9) Turbine Trip	N.A.
b. Steam Line Isolation	≤ 2(5)
5. Containment Pressure - High-3	
a. Containment Spray	≤ 32(1)/20(2)
b. Phase "B" Isolation	≤ 31.5
6. Containment Pressure - High-2	
Steam Line Isolation	≤ 2(5)
7. Steam Line Pressure - Negative Rate-High	
Steam Line Isolation	≤ 2(5)
8. Steam Generator Water Level - High-High	
a. Turbine Trip	≤ 2.5
b. Feedwater Isolation	≤ 2(5)
9. Steam Generator Water Level - Low-Low	
a. Start Motor Driven Auxiliary Feedwater Pumps	≤ 60
b. Start Turbine Driven Auxiliary Feedwater Pumps	≤ 60
10. Loss-of-Offsite Power	
Start Turbine Driven Auxiliary Feedwater Pumps	≤ 60
11. Trip of All Main Feedwater Pumps	
Start Motor Driven Auxiliary Feedwater Pumps	N.A.

Table B 3.3.2-2
(Page 3 of 3)

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
12. Auxiliary Feedwater Pump Suction Pressure-Low Transfer to Essential Service Water	≤ 60(1)
13. RWST Level-Low-Low Coincident with Safety Injection Automatic Switchover to Containment Sump	≤ 60

TABLE NOTATIONS

(1) Diesel generator starting and sequence loading delays included.

(2) Diesel generator starting delay not included. Offsite power available.

(3) Diesel generator starting and sequence loading delay included. RHR pumps not included. Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is included.

(4) Diesel generator starting and sequence loading delays not included. Offsite power available. RHR pumps not included. Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is included.

(5) Does not include valve closure time.

(6) Includes time for diesel to reach full speed.

(7) Diesel generator starting and sequence loading delays included. Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is not included. Response time assumes only opening of RWST valves.

BASES

LCO (continued)

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 3 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP) with any RCS cold leg temperature ≤ 368°F. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required. When both RHR loops (or trains) are required to be OPERABLE, the associated Component Cooling Water (CCW) train is required to be OPERABLE. The heat sink for the CCW System is normally provided by the Service Water System or Essential Service Water (ESW) System, as determined by system availability. In MODES 5 and 6, one Diesel Generator (DG) is required to be OPERABLE per LCO 3.8.2, "AC Sources – Shutdown." The same ESW train is required to be OPERABLE to support DG OPERABILITY. Typically, both ESW trains are utilized to support CCW train OPERABILITY. However, a Service Water train can be utilized to support CCW/RHR OPERABILITY if the associated ESW train is inoperable. A SG can perform as a heat sink via natural circulation when it has an adequate water level and is OPERABLE.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side wide range water level of at least two SGs is required to be ≥ 66%.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";

BASES

APPLICABILITY (continued)

LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side wide range water levels < 66%, redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Notes 1 and 4, or if no loop is OPERABLE, all operations involving introduction into the RCS, coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent inadvertent criticality during a boron dilution, forced circulation from at least one RCP is required to provide proper mixing. Suspending the introduction into the RCS, coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

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

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops - MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the residual heat removal (RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport and to require that two paths be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The flow provided by one RHR loop is adequate for decay heat removal.

The operation of one RCP in MODES 3, 4, and 5 provides adequate flow to ensure mixing, prevent stratification, and produce gradual reactivity changes during RCS boron concentration reductions. With no reactor coolant loop in operation in either MODES 3, 4, or 5, dilution sources must be isolated and administratively controlled. The boron dilution analysis in these MODES take credit for the mixing volume associated with having at least one reactor coolant loop in operation (Ref. 1).

RCS loops in MODE 5 (loops not filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one running RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to meet single failure considerations.

BASES

LCO (continued)

Note 1 permits all RHR pumps to be removed from operation for ≤ 1 hour. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and core outlet temperature is maintained at least 10°F below saturation temperature. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1 is maintained or draining operations when RHR forced flow is stopped. The Note requires reactor vessel water level be above the vessel flange to ensure the operating RHR pump will not be intentionally deenergized during mid-loop operations.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when these tests are safe and possible.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. When both RHR loops (or trains) are required to be OPERABLE, the associated Component Cooling Water (CCW) train is required to be OPERABLE. The heat sink for the CCW System is normally provided by the Service Water System or Essential Service Water (ESW) System, as determined by system availability. In MODES 5 and 6, one Diesel Generator (DG) is required to be OPERABLE per LCO 3.8.2, "AC Sources – Shutdown." The same ESW train is required to be OPERABLE to support DG OPERABILITY. Typically, both ESW trains are utilized to support CCW train OPERABILITY. However, a Service Water train can be utilized to support CCW/RHR OPERABILITY if the associated ESW train is inoperable.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System. One RHR loop provides sufficient capability for this purpose. However, one additional RHR loop is required to be OPERABLE to meet single failure considerations.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

BASES

APPLICABILITY (continued)

Since LCO 3.4.8 contains Required Actions with immediate Completion Times, it is not permitted to enter LCO 3.4.8 from either LCO 3.4.7, RCS Loops – MODE 5, Loops Filled," or from MODE 6, unless the requirements of LCO 3.4.8 are met. This precludes removing the heat removal path afforded by the steam generators with the RHR System is degraded.

ACTIONS

A.1

If only one RHR loop is OPERABLE and in operation, redundancy for RHR is lost. Action must be initiated to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no required RHR loops are OPERABLE or in operation, except during conditions permitted by Note 1, all operations involving introduction into the RCS, coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status and operation. Boron dilution requires forced circulation from at least one RCP for proper mixing so that inadvertent criticality can be prevented. Suspending the introduction into the RCS, coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.8.2

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

REFERENCES

1. USAR, Section 15.4.6.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops - MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 5.5.9, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.9, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.9. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of an SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for an SGTR assumes the contaminated secondary fluid is released to the atmosphere via SG atmospheric relief valves and safety valves.

The analysis for design basis accidents and transients other than an SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture.) In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 1 gallon per minute or is assumed to increase to 1 gallon per minute as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 100 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During a SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. For Refueling Outage 17 and the subsequent operating cycle, a one-time alternate repair criterion for the portion of the tube below 13.1 inches from the top of the tubesheet is specified in TS 5.5.9c.1. (Ref. 7) The tube-to-tubesheet weld is not considered part of the tube.

BASES

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."

2. 10 CFR 50 Appendix A, GDC 19.

3. 10 CFR 100.

4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.

5. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.

6. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

7. License Amendment No. 186, October 19, 2009.

BASES

LCO

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single failure affecting either train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

In MODES 1, 2, and 3, an ECCS train consists of a centrifugal charging subsystem, an SI subsystem, and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an SI signal and automatically transferring suction to the containment sump.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the four cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to supply its flow to the RCS hot and cold legs.

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. Reference 6 describes situations in which one component, such as an RHR crossover valve, can disable both ECCS trains.

During recirculation operation, the flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

As indicated in Note 1, the SI flow paths may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily restorable from the control room, and a single active failure is not assumed coincident with this testing (Ref. 7). Therefore, the ECCS trains are considered OPERABLE during this isolation.

As indicated in Note 2, operation in MODE 3 with ECCS pumps made incapable of injecting, pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is necessary for plants with an LTOP arming temperature at or near the MODE 3 boundary temperature of 350°F. LCO 3.4.12 requires that certain pumps be rendered incapable of injecting at and below the LTOP arming temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to restore the inoperable pumps to OPERABLE status.

BASES

LCO (continued)	Either of the CCPs may be considered OPERABLE with its associated discharge to RCP seal throttle valve, BG-HV-8357A or BG-HV-8357B, inoperable.
APPLICABILITY	In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The centrifugal charging pump performance is based on a small break LOCA, which establishes the pump performance curve and has less dependence on power. The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis. This LCO is only applicable in MODE 3 and above. Below MODE 3, the system functional requirements are relaxed as described in LCO 3.5.3, "ECCS - Shutdown." In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."
ACTIONS	<u>A.1</u> With one or more trains inoperable, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 5) and is a reasonable time for repair of many ECCS components. An ECCS train is inoperable if it is not capable of delivering design flow to the RCS. Individual components are inoperable if they are not capable of performing their design function or supporting systems are not available. The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not render

BASES

ACTIONS

A.1 (continued)

the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

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

B.1 and B.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1

Condition A is applicable with one or more trains inoperable. The allowed Completion Time is based on the assumption that at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train is available. With less than 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the unit is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in the correct position by a power lockout isolation device ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. These valves are of the type, described in References 7 and 8, that can disable the function of both ECCS trains and invalidate the accident analyses. A 12 hour Frequency is considered reasonable in view of other administrative controls that will ensure a mispositioned valve is unlikely.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.2

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

SR 3.5.2.3

The ECCS pumps are normally in a standby, nonoperating mode. As such, flow path piping has the potential to develop voids and pockets of entrained gases. It is important that the ECCS is sufficiently filled with water to ensure that the subsystems can reliably perform their intended function under all LOCA and non-LOCA conditions that require makeup to the RCS. Maintaining the piping from the ECCS pumps to the RCS sufficiently full of water ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This SR is satisfied by verifying that RHR and SI pump casings and accessible ECCS suction and discharge piping high point vents are sufficiently full of water by venting and/or ultrasonic testing (UT). The design of the centrifugal charging pump is such that significant noncondensible gases do not collect in the pump. Therefore, it is unnecessary to require periodic pump casing venting to ensure the centrifugal charging pump will remain OPERABLE. Accessible high point vents are those that can be reached without hazard or high radiation dose to personnel. This will also prevent water hammer, pump cavitation, and pumping of noncondensible gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling. The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping and the procedural controls governing system operation.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. The following ECCS pumps are required to develop the indicated differential pressure on recirculation flow:

Centrifugal Charging Pump	≥ 2490 psid
Safety Injection Pump	≥ 1468.9 psid
RHR Pump	≥ 183.6 psid

This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the applicable portions of the Inservice Testing Program, which encompasses the ASME Code. The ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.5 and SR 3.5.2.6

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and on an actual or simulated RWST Level Low-Low 1 Automatic Transfer signal coincident with an SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned plant transients if the Surveillances were performed with the reactor at power. The 18 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.7

The position of throttle valves in the flow path is necessary for proper ECCS performance. These valves are necessary to restrict flow to a ruptured cold leg, ensuring that the other cold legs receive at least the required minimum flow. The 18 month Frequency is based on the same reasons as those stated in SR 3.5.2.5 and SR 3.5.2.6. The ECCS throttle valves are set to ensure proper flow resistance and pressure drop in the piping to each injection point in the event of a LOCA. Once set, these throttle valves are secured with locking devices and mechanical position stops. These devices help to ensure that the following safety analyses assumptions remain valid: (1) both the maximum and minimum total system resistance; (2) both the maximum and minimum branch injection line resistance; and (3) the maximum and minimum ranges of potential pump performance. These resistances and pump performance ranges are used to calculate the maximum and minimum ECCS flows assumed in the LOCA analyses of Reference 3.

SR 3.5.2.8

This SR requires verification that each ECCS train containment sump inlet is not restricted by debris and the suction inlet strainers show no evidence of structural distress or abnormal corrosion. A visual inspection of the suction inlet piping verifies the piping is unrestricted. A visual inspection of the accessible portion of the containment sump strainer assembly verifies no evidence of structural distress or abnormal corrosion. Verification of no evidence of structural distress ensures there are no openings in excess of the maximum designed strainer opening. The 18 month Frequency has been found to be sufficient to detect abnormal degradation and is confirmed by operating experience.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.
2. 10 CFR 50.46.
3. USAR, Sections 6.3 and 15.6.
4. USAR, Chapter 15, "Accident Analysis."
5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
6. IE Information Notice No. 87-01.

BASES

REFERENCES (continued)

7. BTP EICSB-18, Application of the Single Failure Criteria to Manually-Controlled Electrically-Operated Valves.

8. WCAP-9207, "Evaluation of Mispositioned ECCS Valves," September 1977.

BASES

ACTIONS (continued)

C.1 and C.2

In the event one containment isolation valve in two or more separate penetration flow paths is inoperable, except for purge valve leakage not within limit, all but one of 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 criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with C.1, the device used to isolate the penetration should be the closest available one to containment. Required Action C.1 must be completed within 4 hours. For the penetration flow paths isolated in accordance with Required Action C.1, the affected penetration(s) must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic verification is necessary to assure that the penetrations requiring isolation following an accident are isolated. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting Containment OPERABILITY during MODES 1, 2, 3, and 4.

This Condition is applicable when multiple containment isolation valves in separate flow paths are inoperable. For subsequent containment isolation valve inoperabilities, the Required Action and Completion Time continue to apply to each additional containment isolation valve inoperability, with the Completion Time based on each subsequent entry into the Condition consistent with Note 2 to the ACTIONS Table (e.g., for each entry into the Condition). The containment isolation valve(s) inoperable as a result of that entry shall meet the Required Action and Completion Time.

D.1, D.2, and D.3

In the event one or more containment shutdown or mini-purge valves in one or more penetration flow paths are not within the leakage limits, leakage must be restored to within limits, or the affected penetration flow path 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 (this includes power operated valves with power removed), or blind flange. A containment shutdown purge or mini-purge valve with resilient seals utilized to satisfy Required Action D.1 must have been demonstrated to meet the leakage requirements of SR 3.6.3.6 or SR 3.6.3.7. The specified Completion Time is reasonable, considering that one containment purge valve remains closed so that a gross breach of containment does not exist.

BASES

ACTIONS

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

In accordance with Required Action D.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, through a system walkdown (which may include the use of local or remote indicators), that those isolation devices outside containment capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the 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.

For the containment purge valve with resilient seal that is isolated in accordance with Required Action D.1, SR 3.6.3.6 or SR 3.6.3.7 must be performed at least once every 92 days. This assures that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.3.7, 184 days, is based on an NRC initiative, Multi-Plant Action No. B-20 (Ref. 3). 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 to be acceptable based on operating experience.

Required Action D.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. 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 of these valves, once they have been verified to be in the proper position, is small.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray and Cooling Systems

BASES

BACKGROUND

The Containment Spray and Containment Cooling system provides containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability of the spray reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The Containment Spray and Containment Cooling system is designed to meet the requirements of 10 CFR 50, Appendix A, GDC 38, "Containment Heat Removal," GDC 39, "Inspection of Containment Heat Removal Systems," GDC 40, "Testing of Containment Heat Removal Systems," GDC 41, "Containment Atmosphere Cleanup," GDC 42, "Inspection of Containment Atmosphere Cleanup Systems," and GDC 43, "Testing of Containment Atmosphere Cleanup Systems," and GDC 50, "Containment Design Bases" (Ref. 1).

The Containment Cooling System and Containment Spray System are Engineered Safety Feature (ESF) systems. They are designed to ensure that the heat removal capability required during the post accident period can be attained. The Containment Spray System and the Containment Cooling System provides a redundant method to limit and maintain post accident conditions to less than the containment design values.

Containment Spray System

The Containment Spray System consists of two separate trains of equal capacity, each capable of meeting the design bases. Each train includes a containment spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate ESF bus. The refueling water storage tank (RWST) supplies borated water to the Containment Spray System during the injection phase of operation. In the recirculation mode of operation, containment spray pump suction is transferred from the RWST to the containment recirculation sumps.

The Containment Spray System provides a spray of borated water mixed with sodium hydroxide (NaOH) from the Spray Additive System into the upper regions of containment to reduce the containment pressure and temperature and to reduce fission products from the containment atmosphere during a DBA. The RWST solution temperature is an important factor in determining the heat removal capability of the Containment Spray System during the injection phase. In the recirculation mode of operation, heat is removed from the containment recirculation sump water by the residual heat removal heat exchangers. Each train of the Containment Spray System provides adequate spray

BASES

BACKGROUND

Containment Spray System (continued)

coverage to meet the system design requirements for containment heat removal. The Spray Additive System injects an NaOH solution into the spray. The resulting alkaline pH of the spray enhances the ability of the spray to scavenge fission products from the containment atmosphere. The NaOH added in the spray also ensures an alkaline pH for the solution recirculated in the containment recirculation sump. The alkaline pH of the containment sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The Containment Spray System is actuated either automatically by a containment High-3 pressure signal or manually. An automatic actuation opens the containment spray pump discharge valves, starts the two containment spray pumps and begins the injection phase. A manual actuation of the Containment Spray System requires the operator to simultaneously actuate two separate switches on the main control board to begin the same sequence. The injection phase continues until an RWST level Low-Low alarm is received. The Low-Low level alarm for the RWST signals the operator to manually align the system to the recirculation mode. The Containment Spray System in the recirculation mode maintains an equilibrium temperature between the containment atmosphere and the recirculated sump water. Operation of the Containment Spray System in the recirculation mode is controlled by the operator in accordance with the emergency operating procedures.

Containment Cooling System

Two trains of containment cooling, each of sufficient capacity to supply 100% of the design cooling requirement, are provided. Each train of two fan units is supplied with cooling water from a separate train of essential service water (ESW). Air is drawn into the coolers through the fan and discharged to the steam generator compartments, pressurizer compartment, and instrument tunnel, and outside the secondary shield in the lower areas of containment.

During normal operation, all four fan units are normally operating. The fans are normally operated at high speed with ESW supplied to the cooling coils. The Containment Cooling System, operating in conjunction with the Containment Ventilation and Air Conditioning systems, is designed to limit the ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

BASES

BACKGROUND

Containment Cooling System (continued)

In post accident operation following an actuation signal, the Containment Cooling System fans are designed to start automatically in slow speed if not already running. If running in high (normal) speed, the fans automatically shift to slow speed. The fans are operated at the lower speed during accident conditions to prevent motor overload from the higher mass atmosphere. The temperature of the ESW is an important factor in the heat removal capability of the fan units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limits the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regards to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and Containment Cooling System being rendered inoperable.

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is 51.5 psig and the peak containment temperature is 360.0°F (experienced during an SLB). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.) The analyses and evaluations assume a unit specific power level ranging to 102%, one containment spray train and one containment cooling train operating, and initial (pre-accident) containment conditions of 120°F and 0 psig. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 2).

The effect of an inadvertent containment spray actuation has been analyzed. An inadvertent spray actuation results in a -2.72 psig containment pressure and is associated with the sudden cooling effect in the interior of the leak tight containment. Additional discussion is provided in the Bases for LCO 3.6.4.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The modeled Containment Spray System actuation from the containment analysis is based on a response time associated with exceeding the containment High-3 pressure setpoint to achieving full flow through the containment spray nozzles.

The Containment Spray System total response time includes diesel generator (DG) startup (for loss of offsite power), sequenced loading of equipment, containment spray pump startup, and spray line filling (Ref. 4).

Containment cooling train performance for post accident conditions is given in Reference 4. The result of the analysis is that each train can provide 100% of the required peak cooling capacity during the post accident condition. The train post accident cooling capacity under varying containment ambient conditions, required to perform the accident analyses, is also shown in Reference 4.

The modeled Containment Cooling System actuation from the containment analysis is based upon a response time associated with receipt of an SI signal to achieving full Containment Cooling System air and safety grade cooling water flow. The Containment Cooling System total response time of 70 seconds, includes signal delay, DG startup (for loss of offsite power), and Essential Service Water pump startup times and line refill (Ref. 4).

The Containment Spray System and the Containment Cooling System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, a minimum of one containment cooling train and one containment spray train is required to maintain the containment peak pressure and temperature below the design limits (Ref. 3). Additionally, one containment spray train is also required to remove iodine from the containment atmosphere and maintain concentrations below those assumed in the safety analysis. With the Spray Additive System inoperable, a containment spray train is still available and would remove some iodine from the containment atmosphere in the event of a DBA. To ensure that these requirements are met, two containment spray trains and two containment cooling trains must be OPERABLE. Therefore, in the event of an accident, at least one train in each system operates, assuming the worst case single active failure occurs.

Each Containment Spray System typically includes a spray pump, spray headers, eductor, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal and manually transferring to the containment sump.

A containment cooling train typically includes cooling coils, dampers, two fans, instruments, and controls to ensure an OPERABLE flow path.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Spray Additive System

BASES

BACKGROUND

The Spray Additive System is a subsystem of the Containment Spray System that assists in reducing the iodine fission product inventory in the containment atmosphere resulting from a Design Basis Accident (DBA).

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. It is absorbed by the spray from the containment atmosphere. To enhance the iodine absorption capacity of the spray, the spray solution is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. Because of its stability when exposed to radiation and elevated temperature, sodium hydroxide (NaOH) is the preferred spray additive. The NaOH added to the spray also ensures a pH value of between 8.5 and 11.0 of the solution recirculated from the containment sump. This pH band minimizes the evolution of iodine as well as the occurrence of chloride and caustic stress corrosion on mechanical systems and components.

The Spray Additive System consists of one spray additive tank that is shared by the two trains of spray additive equipment. Each train of equipment provides a flow path from the spray additive tank to a containment spray pump and consists of an eductor for each containment spray pump, valves, instrumentation, and connecting piping. Each eductor draws the NaOH spray solution from the common tank using a portion of the borated water discharged by the containment spray pump as the motive flow. The eductor mixes the NaOH solution and the borated water and discharges the mixture into the spray pump suction line. The eductors are designed to ensure that the pH of the spray mixture is between 9.0 and 11.0.

The Containment Spray System actuation signal opens the valves from the spray additive tank to the spray pump suctions. The 28% to 31% NaOH solution is drawn into the spray pump suctions. The spray additive tank capacity provides for the addition of NaOH solution to all of the water sprayed from the RWST into containment. The percent solution and volume of solution sprayed into containment ensures a long term containment sump pH of ≥ 8.5 and ≤ 11.0. This ensures the continued iodine retention effectiveness of the sump water during the recirculation phase of spray operation and also minimizes the occurrence of chloride induced stress corrosion cracking of the stainless steel recirculation piping.

BASES

APPLICABLE SAFETY ANALYSES

The Spray Additive System is essential to the removal of airborne iodine within containment following a DBA.

Following the assumed release of radioactive materials into containment, the containment is assumed to leak at its design value volume following the accident. The analysis assumes that 85% of the containment free volume is covered by the spray (Ref. 1).

The DBA analysis credit for iodine removal by Containment Spray System is taken, starting at time zero and continuing until a decontamination factor of 100.

The DBA analyses assume that one train of the Containment Spray System/Spray Additive System is inoperable and that the entire spray additive tank volume is added to the remaining Containment Spray System flow path.

The Spray Additive System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The Spray Additive System is necessary to reduce the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, the volume and concentration of the spray additive solution must be sufficient to provide NaOH injection into the spray flow to raise the average long term containment sump solution pH to a level conducive to iodine removal, namely, to between 8.5 and 11.0. This pH range maximizes the effectiveness of the iodine removal mechanism without introducing conditions that may induce caustic stress corrosion cracking of mechanical system components.

The Spray Additive System typically includes a spray additive tank, eductors, valves, instrumentation, and connected piping to ensure OPERABLE flow paths. In addition, it is essential that valves in the Spray Additive System flow paths are properly positioned and that automatic valves are capable of activating to their correct positions.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the Spray Additive System. The Spray Additive System assists in reducing the iodine fission product inventory prior to release to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the Spray Additive System is not required to be OPERABLE in MODE 5 or 6.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.7.5 (continued)

the eductor inlet to simulate flow from the spray additive tank. This SR provides assurance that the correct amount of NaOH will be metered into the flow path upon Containment Spray System initiation. Due to the passive nature of the spray additive flow controls, the 5 year Frequency is sufficient to identify component degradation that may affect flow rate.

REFERENCES

1. USAR, Chapter 15.6.5.4.
2. Configuration Change Package 09334.
3. Performance Improvement Request 2006-0425.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs) and MSIV Bypass Valves

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators to the break.

One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, Turbine Bypass System, and other auxiliary steam supplies from the steam generators.

The MSIV is a 28-inch gate valve with system-medium actuation trains. Either actuation train can independently perform the safety function to fast-close the MSIV on demand. For each MSIV, one actuator train is associated with separation group 4 ("yellow"), and one actuator train is associated with separation group 1 ("red").

The MSIVs close on a main steam isolation signal generated by low steam line pressure, high steam line negative pressure rate or High-2 containment pressure. The MSIVs fail as is on loss of control or actuation power.

Each MSIV has an MSIV bypass valve. Although the bypass valves are normally closed, they receive the same emergency closure signals as the associated MSIV. The MSIV bypass valves are open when the MSIVs are closed, to permit warming of the main steam lines prior to startup. The MSIV bypass valves are air-operated globe valves. For emergency closure of each MSIV bypass valve, either of two separate solenoid valves, when de-energized, will result in valve closure. The two electrical solenoid valves are energized from separate Class 1E sources.

A description of the MSIVs and MSIV bypass valves is found in the USAR, Section 10.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs and MSIV bypass valves is established by the containment analysis for the large steam line break (SLB) inside containment, discussed in the USAR, Section 6.2.1.4 (Ref. 2). It is also

BASES

APPLICABLE SAFETY ANALYSES (continued)

affected by the accident analysis of the SLB events presented in the USAR, Section 15.1.5 (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV or MSIV bypass valve to close on demand).

The limiting case for the containment pressure analysis is the SLB inside containment, with initial reactor power at approximately 0% with loss of offsite power and the failure of one emergency diesel generator. At lower powers, the steam generator inventory and temperature are at their maximum, maximizing the analyzed mass and energy release to the containment. Due to reverse flow and failure of the MSIV to close,the additional mass and energy in the steam headers downstream from the other MSIV contribute to the total release. With the most reactive rod cluster control assembly assumed stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid injection delivered by the Emergency Core Cooling System.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at hot zero power is the limiting case for a post trip return to power. The analysis includes scenarios with offsite power available, and with a loss of offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System cooldown. With a loss of offsite power, the response of mitigating systems is delayed. Significant single failures considered include failure of an MSIV to close.

The MSIVs serve only a safety function and remain open during power operation. The MSIV bypass valves are typically used for turbine warming and pressure equalization during startup, and are normally closed during power operation, but may be opened, for example, for testing or maintenance. These valves operate under the following situations:

a. An HELB inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSIV in the affected steam generator remains open. For this accident scenario, steam is discharged into containment from all steam generators until the remaining MSIVs and MSIV bypass valves close. After MSIV and MSIV bypass valve closure, steam is

BASES

APPLICABLE SAFETY ANALYSES (continued)

discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIVs in the unaffected loops. Closure of the MSIVs (and MSIV bypass valves) isolates the break from the unaffected steam generators.

b. A break outside of containment and upstream from the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs (and MSIV bypass valves) isolates the break and limits the blowdown to a single steam generator.

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs and the closed MSIV bypass valves.

d. Following a steam generator tube rupture, closure of the MSIVs (and MSIV bypass valves) isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

e. The MSIVs and MSIV bypass valves are also utilized during other less limiting events such as a feedwater line break.

The MSIVs and MSIV bypass valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that four MSIVs and their associated actuator trains, and four MSIV bypass valves be OPERABLE. The MSIVs are considered OPERABLE when isolation times are within limits of Figure B 3.7.2-1 when given a close signal and they are capable of closing on an isolation actuation signal. An MSIV actuator train is considered OPERABLE when it is capable of closing the associated MSIV on demand and within the required isolation time. The MSIV bypass valves are considered OPERABLE when their isolation times are within limits and they are capable of closing on an isolation actuation signal.

The LCO is modified by two Notes. Note 1 allows all MSIVs and their associated actuator trains to be inoperable in MODES 2 and 3 when closed and de-activated. When all MSIVs are closed and de-activated, they are performing the specified safety function. Closing and de-activating provides a means of isolation that cannot be adversely affected by a single active failure, thus assuring the MSIV is performing the specified safety function. To de-activate the MSIVs, the electrical power

BASES

LCO (continued)

sources must be removed from the actuation solenoids on all four MSIVs and a drain or vent path must be available from the lower piston chamber. Note 2 allows one or more MSIV bypass valve to be inoperable when closed and de-activated, closed and isolated by a closed manual valve, or isolated by two closed manual valves. When one or more MSIV bypass valves are closed and de-activated, closed and isolated by a closed manual valve, or isolated by two closed manual valves, they are performing their specified safety function. When the valve is de-activated, power and air are removed from both actuation solenoid valves and the valve is spring closed. Requiring the MSIV bypass valve to be closed and isolated by a closed manual valve or isolated by two closed manual valves also provides the dual assurance that the specified safety function is being performed.

This LCO provides assurance that the MSIVs and MSIV bypass valves will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 (Ref. 4) limits or the NRC staff approved licensing basis.

APPLICABILITY

The MSIVs and MSIV bypass valves must be OPERABLE in MODE 1, and in MODES 2 and 3 due to significant mass and energy in the RCS and steam generators. When the MSIVs and MSIV bypass valves are closed, they are already performing the safety function. The MSIV actuator trains must be OPERABLE in MODES 1, 2, and 3 to support operation of the MSIV.

In MODE 4, 5 or 6, the steam generator energy is low. Therefore, the MSIVs and MSIV bypass valves are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

The LCO specifies OPERABILITY requirements for the MSIVs as well as for their associated actuator trains. The Conditions and Required Actions for TS 3.7.2 separately address inoperability of the MSIV actuator trains and inoperability of the MSIVs themselves.

A.1

With a single actuator train inoperable on one MSIV, action must be taken to restore the inoperable actuator train to OPERABLE status within 7 days. The 7-day Completion Time is reasonable in light of the dual-redundant actuator train design such that with one actuator train inoperable, the affected MSIV is still capable of closing on demand via the

BASES

ACTIONS A.1 (continued)

remaining OPERABLE actuator train. The 7-day Completion Time takes into account the redundant OPERABLE actuator train to the MSIV, reasonable time for repairs, and the low probability of an event occurring that requires the inoperable actuator train to the affected MSIV.

B.1

With an actuator train on one MSIV inoperable and an actuator train on an additional MSIV inoperable, such that the inoperable actuator trains are not in the same separation group, action must be taken to restore one of the inoperable actuator trains to OPERABLE status within 72 hours. With two actuator trains inoperable on two MSIVs, there is an increased likelihood that an additional failure (such as the failure of an actuation logic train) could cause one MSIV to fail to close. The 72-hour Completion Time is reasonable since the dual-redundant actuator train design ensures that with only one actuator train on each of two affected MSIVs inoperable, each MSIV is still capable of closing on demand.

C.1

With an actuator train on one MSIV inoperable and an actuator train on an additional MSIV inoperable, but with both inoperable actuator trains in the same separation group, action must be taken to restore one of the inoperable actuator trains to OPERABLE status within 24 hours. The 24-hour Completion Time provides a reasonable amount of time for restoring at least one actuator train since the dual-redundant actuator train design for each MSIV ensures that a single inoperable actuator train cannot prevent the affected MSIV(s) from closing on demand. With two actuator trains inoperable in the same separation group, an additional failure (such as the failure of an actuation logic train in the other separation group) could cause both affected MSIVs to fail to close on demand. The 24 hour Completion Time takes into the redundant OPERABLE actuator trains to the affected MSIVs and the low probability of an event occurring that requires the inoperable actuator trains to the affected MSIVs.

BASES

ACTIONS (continued)

D.1

Required Action D.1 provides assurance that the appropriate Action is entered for the affected MSIV if its associated actuator trains become inoperable. Failure of both actuator trains for a single MSIV results in the inability to close the affected MSIV on demand.

E.1

With three or more MSIV actuator trains inoperable or when Required Action A.1, B.1, or C.1 cannot be completed within the required Completion Time, the affected MSIVs may be incapable of closing on demand and must be immediately declared inoperable. Having three actuator trains inoperable could involve two inoperable actuator trains on one MSIV and one inoperable actuator train on another MSIV, or an inoperable actuator train on each of three MSIVs, for which the inoperable actuator trains could all be in the same separation group or be staggered among the two separation groups.

Depending on which of these conditions or combinations is in effect, the condition or combination could mean that all of the affected MSIVs remain capable of closing on demand (due to the dual-redundant actuator train design), or that at least one MSIV is inoperable, or that with an additional single failure up to three MSIVs could be incapable of closing on demand. Therefore, in some cases, immediately declaring the affected MSIVs inoperable is conservative (when some or all of the affected MSIVs may still be capable of closing on demand even with a single additional failure), while in other cases it is appropriate (when at least one of the MSIVs would be inoperable, or up to three could be rendered inoperable by an additional single failure). Required Action E.1 is conservatively based on the worst-case condition and therefore requires immediately declaring all the affected MSIVs inoperable. Declaring two or more MSIVs inoperable while in MODE 1 requires entry into LCO 3.0.3.

F.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to the MSIV can be made with the unit hot. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs. Condition F is entered when one MSIV is inoperable in MODE 1, including when both actuator trains for one MSIV are inoperable. When only one actuator train is inoperable on one MSIV, Condition A applies.

BASES

ACTIONS (continued)

G.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, 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 MODE 2 within 6 hours and Condition H would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

H.1 and H.2

Condition H is modified by a Note indicating that separate Condition entry is allowed for each MSIV bypass valve.

With one or more MSIV bypass valves inoperable, action must be taken to restore each MSIV bypass valve to OPERABLE status within 8 hours or the inoperable MSIV bypass valve must be closed or isolated. When closed or isolated, the MSIV bypass valve is in the position required by the assumptions in the safety analysis. The 8 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an accident occurring during this time period that would require a closure of the MSIV bypass valves.

For inoperable MSIV bypass valves that cannot be restored to OPERABLE status within 8 hours, but are closed or isolated, the inoperable MSIV bypass valves must be verified on a periodic basis to be closed or isolated. This is necessary to assure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls to ensure that these valves are closed or isolated.

I.1 and I.2

Condition I is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is consistent with that allowed in Condition F.

BASES

ACTIONS

I.1 and I.2 (continued)

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid.

The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

J.1 and J.2

If the Required Actions of Condition H or I are not met, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that the closure time of each MSIV is within the limits of Figure B 3.7.2-1 from each actuator train when tested pursuant to the Inservice Testing Program. The MSIV isolation time is explicitly assumed in the accident analyses that credit the Steam Line Isolation. Figure B 3.2.7-1 is a curve of the MSIV isolation time limit as a function of steam generator pressure. The acceptance curve for the MSIV stroke time conservatively accounts for potential pressure differential between the steam generator pressure indication and the pressure at the MSIV. This Surveillance is normally performed upon returning the unit to operation following a refueling outage.

The Frequency is in accordance with the Inservice Testing Program.

This test can be conducted in MODE 3 with the unit at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.2

This SR verifies that each actuator train can close its respective MSIV on an actual or simulated actuation signal. The manual fast close hand switch in the control room provides an acceptable actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

The frequency of MSIV testing is every 18 months. The 18 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

SR 3.7.2.3

This SR verifies that each MSIV bypass valve can close on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage. The Frequency of MSIV bypass valve testing is every 18 months. The 18 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

SR 3.7.2.4

This SR verifies that the closure time of each MSIV bypass valve is ≤ 15 seconds when tested pursuant to the Inservice Testing Program. This is consistent with the assumptions used in the accident and containment analyses. For the MSIV bypass valves, this Surveillance is performed routinely during plant operation (or as required for post-maintenance testing, but it may also be required to be performed upon returning the unit to operation following a refueling outage.

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

BASES

REFERENCES

1. USAR, Section 10.3.
2. USAR, Section 6.2.
3. USAR, Section 15.1.5.
4. 10 CFR 100.11.

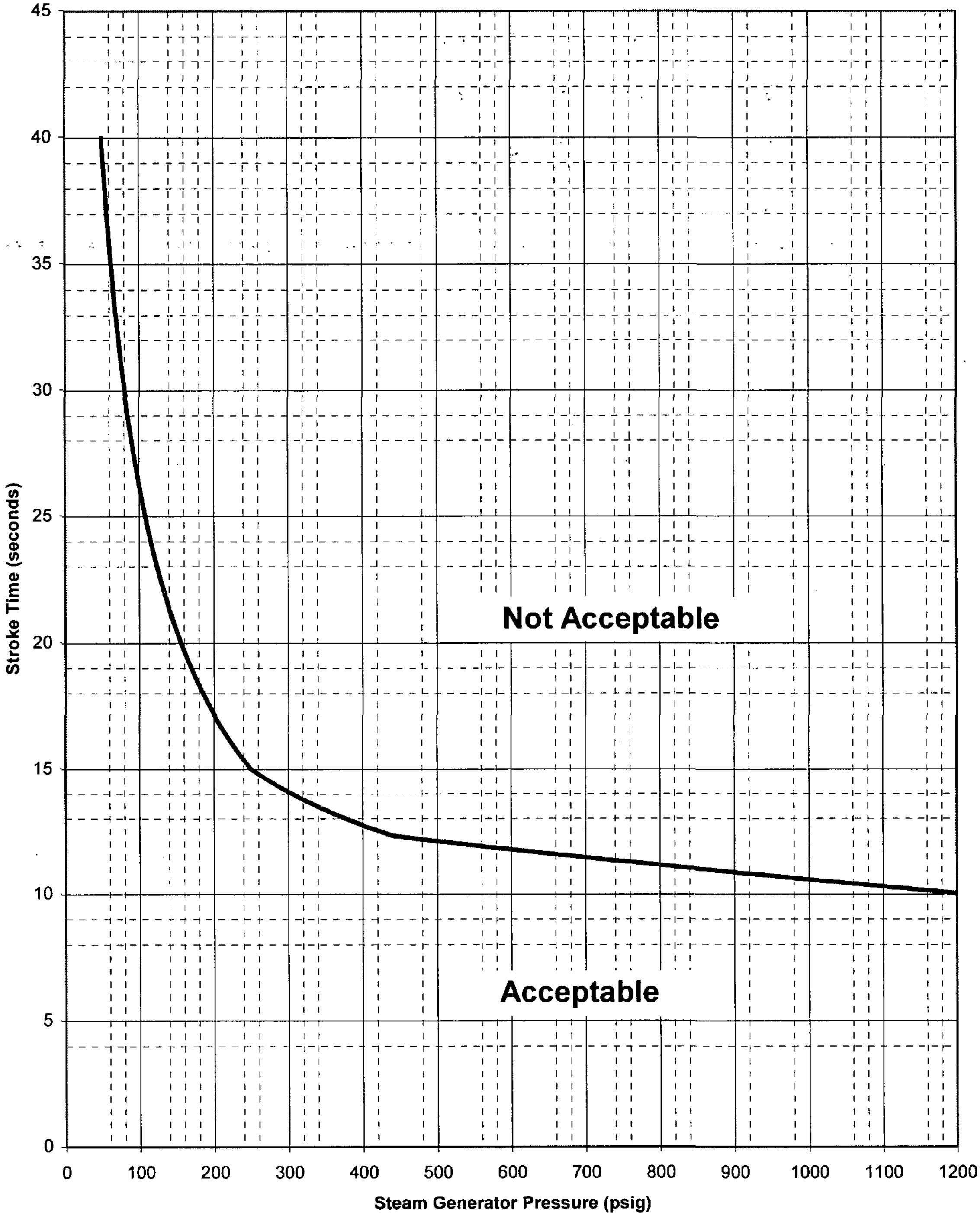

Figure B 3.7.2-1
MSIV Isolation Time vs. Steam Generator Pressure

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. Feedwater Line Break (FWLB);

b. Main Steam Line Break; and

c. Loss of MFW.

In addition, the minimum available AFW flow and system characteristics are considerations in the analysis of a small break loss of coolant accident (LOCA). The AFW System design is such that it can perform its function following an FWLB between the MFW isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure of one motor driven AFW pump. This results in minimum assumed flow to the intact steam generators. One motor driven AFW pump would deliver to the broken MFW header at a flow rate throttled by the motor operated "smart" discharge valve until the problem was detected, and flow terminated by the operator. Sufficient flow would be delivered to the intact steam generator by the residual flow from the affected pump plus the turbine driven AFW pump.

The BOP ESFAS automatically actuates the AFW turbine driven pump when required to ensure an adequate feedwater supply to the steam generators during loss of power. DC power operated valves are provided for each AFW line to control the AFW flow to each steam generator.

The AFW System satisfies the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three independent AFW pumps in three diverse trains are required to be OPERABLE to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

The AFW System is configured into three trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each capable of automatically transferring the suction from

BASES

LCO (continued)

the CST to an ESW supply and supplying AFW to two steam generators. The turbine driven AFW pump is required to be OPERABLE with redundant steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of automatically transferring the suction from the CST to an ESW supply and supplying AFW to any of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE. The inoperability of a single supply line or a single suction isolation valve from an ESW train to the turbine driven AFW pump causes a loss of redundancy in ESW supply to the pump but does not render the turbine driven AFW train inoperable. The supply line begins at the point where the ESW piping branches into two lines, one supplying the motor driven AFW pump and one supplying the turbine driven AFW pump, and ends at the suction of the turbine driven AFW pump (Ref. 3). Therefore, with one ESW train inoperable, the associated motor driven AFW train is considered inoperable; and one turbine driven AFW pump supply line is considered inoperable. However, the turbine driven AFW train is OPERABLE based on the remaining OPERABLE ESW supply line.

In order for the turbine driven AFW pump and motor driven AFW pumps to be OPERABLE while the AFW System is in automatic control or above 10% RTP, the discharge flow control valves shall be in the full open position, except when the motor driven AFW pumps discharge flow control valves are automatically throttled in response to actual AFW flow (Ref. 5). When ≤ 10% RTP, the turbine driven AFW pump and motor driven AFW pumps remain OPERABLE with the discharge flow control valves throttled as needed to maintain steam generator levels.

The standby lineup for the turbine driven AFW steam supply lines is when the main steam supply valves, ABHV0005 and ABHV0006, are closed and OPERABLE and the warmup valves, ABHV0048 and ABHV0049, are open and OPERABLE. With a main steam supply valve and its associated warmup valve closed, the turbine driven AFW steam supply line is inoperable. The turbine driven AFW pump is inoperable when restoring a steam supply line to service if both the main steam supply valve and its associated warmup valve were closed. The turbine driven AFW pump is inoperable until the condensation has been drained by FCLV0010 not cycling for a minimum of five minutes.

The nitrogen accumulator tanks supplying the turbine driven AFW pump control valves and the steam generator atmospheric relief valves ensure an eight hour supply for the pump and valves.

Although the AFW System may be used in MODE 4 to remove decay heat, the LCO does not require the AFW System to be OPERABLE in MODE 4 since the RHR System is available for decay heat removal.

BASES

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory, lost as the unit cools to MODE 4 conditions.

In MODE 4 the AFW System may be used for heat removal via the steam generators but is not required since the RHR System is available and required to be OPERABLE in this MODE.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

ACTIONS

A Note prohibits the application of LCO 3.0.4b. to an inoperable AFW train when entering MODE 1. There is an increased risk associated with entering MODE 1 with an AFW train inoperable and the provisions of LCO 3.0.4b., which allow entry into a MODE, or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

If one of the two steam supplies to the turbine driven AFW train is inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. The redundant OPERABLE steam supply to the turbine driven AFW pump;

b. The availability of redundant OPERABLE motor driven AFW pumps; and

c. The low probability of an event occurring that requires the inoperable steam supply to the turbine driven AFW pump.

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

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which multiple Conditions are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

BASES

ACTIONS (continued)

B.1

With one of the required AFW trains (pump or flow path) inoperable for reasons other than Condition A, action must be taken to restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the AFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

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

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

When Required Action A.1 or B.1 cannot be completed within the required Completion Time, or if two AFW trains are inoperable , the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours.

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

D.1

If all three AFW trains are inoperable, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety related equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AFW train to OPERABLE status.

Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition.

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Emergency Ventilation System (CREVS)

BASES

BACKGROUND

The CREVS provides a protected, controlled temperature environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The CREVS consists of two independent, redundant trains that recirculate, cool, pressurize, and filter the air in the control room envelope (CRE) and control building envelope (CBE) that limits the inleakage of unfiltered air. Each CREVS train consists of a recirculation system train and a pressurization system train. The air conditioning portion of each train consists of a fan, a self-contained refrigeration system, and a prefilter. The filtration portion of each system consists of a high efficiency particulate air (HEPA) filter, an activated charcoal absorber section for removal of gaseous activity (principally iodines), and a second HEPA follows the absorber section to collect carbon fines. Each pressurization system train consists of ductwork to bring air from outside the building, a moisture separator, an electric heater, a HEPA, an activated charcoal adsorber, and a second HEPA. Ductwork, valves or dampers, doors, barriers, and instrumentation also form part of the system.

The CREVS is an emergency system which may also operate during normal unit operations. Upon receipt of the actuating signal, normal air supply and exhaust to the CRE is isolated, and a portion of the ventilation air is recirculated through the filtration system train(s), and the pressurization system is started. The filtration system prefilters remove any large particles in the air, and the pressurization system moisture separator removes any entrained water droplets present, to prevent excessive loading of the HEPA filters and charcoal adsorbers. Continuous operation of each pressurization train for at least 10 hours per month, with the heaters functioning, reduces moisture buildup on the HEPA filters and adsorbers. The heaters are important to the effectiveness of the charcoal adsorbers.

Actuation of the CREVS by a Control Room Ventilation Isolation Signal (CRVIS), places the system in the emergency mode of operation. Actuation of the system to the emergency mode of operation closes the unfiltered outside air intake and unfiltered exhaust dampers, and aligns the system for recirculation. A portion of the recirculation of the air within the CRE flows through the redundant filtration system trains of HEPA and the charcoal adsorbers. The CRVIS also initiates pressurization and filtered ventilation of the air supply to the CRE.

BASES

BACKGROUND (continued)

Outside air is filtered, diluted with air from the electrical equipment and cable spreading rooms, and added to the air being recirculated from the CRE. Pressurization of the CRE prevents infiltration of unfiltered air from the surrounding areas of the building.

The air entering the CBE during normal operation is continuously monitored by radiation and smoke detectors. A high radiation signal initiates the CRVIS; the smoke detectors provide an alarm in the control room. A CRVIS is initiated by the radiation monitors (GKRE0004 and GKRE0005), fuel building ventilation isolation signal, containment isolation phase A, containment atmosphere radiation monitors (GTRE0031 and GTRE0032), containment purge exhaust radiation monitors (GTRE0022 and GTRE0033), or manually.

A single CREVS train operating in the CREVS alignment established by surveillance procedures will pressurize the control room to ≥ 0.25 inches water gauge. The CREVS operation in maintaining the CRE habitable is discussed in the USAR, Section 6.4 and 9.4 (Ref. 1).

Either of the pressurization and recirculation trains provide the required filtration and pressurization to the CRE. Normally open isolation dampers are arranged in series pairs so that the failure of one damper to shut will not result in a breach of isolation. The CREVS is designed in accordance with Seismic Category I requirements.

The CREVS is designed to maintain a habitable environment in the CRE for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding a 5 rem whole body dose or its equivalent to any part of the body (Ref. 2).

By operation of the control room pressurization trains and the control room filtration units, the CREVS pressurizes, recirculates and filters air within the CRE as well as the CBE that generally surrounds the CRE. The boundaries of these two distinct but related volumes are credited in the analysis of record for limiting the inleakage of unfiltered outside air.

The station CRE design is unique. The Control Building by and large surrounds the CRE. The Control Building is also designed to be at a positive pressure with respect to its surrounding environment although not positive with respect to the CRE. In the emergency pressurization and filtration mode, the control room air volume receives air through a filtration system that takes a suction on the Control Building. The Control Building in turn receives filtered air from the outside environment.

BASES

BACKGROUND (continued)

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

The CBE is an area that largely surrounds the CRE. Occupancy of the CBE is not required to control the unit during normal and accident conditions. The CBE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CBE. The CBE boundary must be maintained to ensure that the inleakage of unfiltered air into the CBE will not exceed the inleakage assumed in the licensing basis analysis of DBA consequences to CRE occupants. The CBE and its boundary are defined in the Control Room Envelope Habitability Program.

APPLICABLE SAFETY ANALYSES

The CREVS components are arranged in redundant, safety related ventilation trains. The location of components and ducting within the CRE ensures an adequate supply of filtered air to all areas requiring access. The CREVS provides airborne radiological protection for the CRE occupants, as demonstrated by the CRE occupant dose analyses for the most limiting design basis accident, fission product release presented in the USAR, Chapter 15, Appendix 15A (Ref. 2).

The CREVS provides protection from smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases (Ref. 7) determined that hazardous chemicals are not stored or used onsite in quantities sufficient to necessitate CRE protection as required by Regulatory Guide 1.78 (Ref. 8). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 1). The analysis for smoke and hazardous chemicals has determined no CREVS actuation for such events.

The worst case single active failure of a component of the CREVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

The CREVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Two independent and redundant CREVS trains are required to be OPERABLE to ensure that at least one is available if a single active failure disables the other train. Total system failure, such as from a loss of both ventilation trains or from an inoperable CRE or CBE boundary, could result in exceeding a dose of 5 rem whole body or its equivalent to any part of the body to the CRE occupants in the event of a large radioactive release.

Each CREVS train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE in both trains. A CREVS train is OPERABLE when the associated:

a. Recirculation and pressurization fans are OPERABLE;

b. HEPA filters and charcoal absorbers are not excessively restricting flow, and are capable of performing their filtration functions;

c. Heater, moisture separator, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained; and

d. Control Room Air Conditioning flow path integrity is maintained.

In order for the CREVS trains to be considered OPERABLE, the CRE and CBE boundaries must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBA's, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE and CBE boundaries to be opened intermittently under administrative controls. This Note only applies to openings in the CRE and CBE boundaries that can be rapidly restored to intended design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and thereby restore the affected envelope boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

Note that the Control Room Air Conditioning System (CRACS) forms a subsystem to the CREVS. The CREVS remains capable of performing its safety function provided the CRACS air flow path is intact and air circulation can be maintained. Isolation or breach of the CRACS air flow path can also render the CREVS flow path inoperable. In these situations LCOs 3.7.10 and 3.7.11 may be applicable.

BASES

APPLICABILITY

In MODES 1, 2, 3, 4, 5, and 6, and during movement of irradiated fuel assemblies, the CREVS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA.

In MODE 5 or 6, the CREVS is required to cope with the design basis release from the rupture of a waste gas tank.

During movement of irradiated fuel assemblies, the CREVS must be OPERABLE to cope with the release from a design basis fuel handling accident.

ACTIONS

A.1

When one CREVS train is inoperable for reasons other than an inoperable CRE or CBE boundary, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CREVS train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE CREVS train could result in loss of CREVS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

B.1, B.2, and B.3

If the unfiltered inleakage of potentially contaminated air past a CRE or CBE boundary credited in the accident analysis and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem whole body or its equivalent to any part of the body), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE or CBE boundary is inoperable. Actions must be taken to restore the CRE or CBE boundary to OPERABLE status within 90 days.

During the period that the CRE or CBE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous

BASES

ACTIONS

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

chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CBP boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional.

The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most conditions adversely affecting the CRE or CBE boundary.

C.1 and C.2

In MODE 1, 2, 3, or 4, if the inoperable CREVS train or the inoperable CRE or CBE boundary cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion 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.

D.1.1, D.1.2, D.2.1, and D.2.2

In MODE 5 or 6, or during movement of irradiated fuel assemblies, if the inoperable CREVS train cannot be restored to OPERABLE status within the required Completion Time, action must be taken to immediately place the OPERABLE CREVS train in the CRVIS mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected. Required Action D.1.2 requires the CREVS train placed in operation be capable of being powered by an emergency power source. This action assures OPERABILITY of the CREVS train in the unlikely event of a fuel handling accident or decay tank rupture while shutdown concurrent with a loss of offsite power.

BASES

ACTIONS

D.1.1, D.1.2, D.2.1, and D.2.2 (continued)

An alternative to Required Action D.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

E.1 and E.2

In MODE 5 or 6, or during movement of irradiated fuel assemblies, with two CREVS trains inoperable or with one or more CREVS trains inoperable due to an inoperable CRE or CBE boundary, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

F.1

If both CREVS trains are inoperable in MODE 1, 2, 3, or 4, for reasons other than an inoperable CRE and CBE boundary (i.e., Condition B), the CREVS may not be capable of performing the intended function and the unit is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, testing each train once every month, by initiating from the control room, flow through the HEPA filters and charcoal adsorber of both the filtration and pressurization systems, provides an adequate check of this system. Monthly heater operations dry out any moisture accumulated in the charcoal from humidity in the ambient air. Each pressurization system train must be operated for ≥ 10 continuous hours with the heaters energized. Each filtration system train need only be operated for ≥ 15 minutes to demonstrate the function of the system. The 31 day Frequency is based on the reliability of the equipment and the two train redundancy.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.2

This SR verifies that the required CREVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CREVS filter tests use the procedure guidance in Regulatory Guide 1.52, Rev. 2 (Ref. 3) in accordance with the VFTP. The VFTP includes testing the performance of the HEPA filter, charcoal absorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.10.3

This SR verifies that each CREVS train starts and operates on an actual or simulated CRVIS. The actuation signal includes Control Room Ventilation or High Gaseous Radioactivity. The CREVS train automatically switches on an actual or simulated CRVIS into a CRVIS mode of operation with flow through the HEPA filters and charcoal adsorber banks. The Frequency of 18 months is consistent with a typical operating cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.10.4

This SR verifies the OPERABILITY of the CRE and CBE boundaries credited in the accident analysis by testing for unfiltered air inleakage past the credited envelope boundaries and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem whole body or its equivalent to any part of the body and the CRE occupants are protected from hazardous chemicals and smoke. For WCGS, there is no CREVS actuation for hazardous chemical releases or smoke and there are no Surveillance Requirements that verify OPERABILITY for hazardous chemicals or smoke. This SR verifies that the unfiltered air inleakage into the CRE and CBE boundaries is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered. Required Action B.3 allows time to restore the CRE or CBE

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.4 (continued)

boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 4) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 5). These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 6). Options for restoring the CRE or CBE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the envelope boundary has been restored to OPERABLE status.

REFERENCES

1. USAR, Section 6.4 and 9.4.
2. USAR, Chapter 15, Appendix 15A.
3. Regulatory Guide 1.52, Rev. 2.
4. Regulatory Guide 1.196.
5. NEI 99-03, "Control Room Habitability Assessment," June 2001.
6. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).
7. USAR Section 2.2.
8. Regulatory Guide 1.78, Rev. 0.

BASES

LCO (continued)

a. Fan is OPERABLE;

b. HEPA filter and charcoal absorber are not excessively restricting flow, and are capable of performing their filtration function; and

c. Heater, ductwork, and dampers are OPERABLE, and air circulation can be maintained.

The LCO is modified by a Note allowing the auxiliary or fuel building boundary to be opened intermittently under administrative controls. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for auxiliary building or fuel building isolation is indicated.

APPLICABILITY

In MODE 1, 2, 3, or 4, the Emergency Exhaust System is required to be OPERABLE in the SIS mode of operation to provide fission product removal associated with potential radioactivity leaks during the post-LOCA recirculation phase of ECCS operation.

In MODE 5 or 6, when not moving irradiated fuel the Emergency Exhaust System is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

During movement of irradiated fuel in the fuel handling area, the Emergency Exhaust System is required to be OPERABLE to support the FBVIS mode of operation to alleviate the consequences of a fuel handling accident.

The Applicability is modified by a Note. The Note clarifies the Applicability for the two safety related modes of operation of the Emergency Exhaust System, i.e., the Safety Injection Signal (SIS) mode and the Fuel Building Ventilation Isolation Signal (FBVIS) mode. The SIS mode which aligns the system to the auxiliary building is applicable when the ECCS is required to be OPERABLE. In the FBVIS mode the system is aligned to the fuel building. This mode is applicable while handling irradiated fuel in the fuel building.

BASES

ACTIONS

A.1

With one Emergency Exhaust System train inoperable in MODE 1, 2, 3, or 4, action must be taken to restore OPERABLE status within 7 days. During this period, the remaining OPERABLE train is adequate to perform the Emergency Exhaust System function. The 7 day Completion Time is based on the risk from an event occurring requiring the inoperable Emergency Exhaust System train, and the remaining Emergency Exhaust System train providing the required protection.

B.1

If the auxiliary building boundary is inoperable such that a train of the Emergency Exhaust System operating in the SIS mode cannot establish or maintain the required negative pressure, action must be taken to restore an OPERABLE auxiliary building boundary within 24 hours. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period and the availability of the Emergency Exhaust System to provide a filtered release (albeit with potential for some unfiltered auxiliary building leakage).

C.1 and C.2

In MODE 1, 2, 3, or 4, when Required Action A.1 or B.1 cannot be completed within the associated Completion Time or when both Emergency Exhaust System trains are inoperable for reasons other than an inoperable auxiliary building boundary (i.e., Condition B), 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 MODE 3 within 6 hours, and in MODE 5 within 36 hours. The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1 and D.2

With one Emergency Exhaust System train inoperable, during movement of irradiated fuel assemblies in the fuel building, the OPERABLE Emergency Exhaust System train must be started in the FBVIS mode immediately or fuel movement suspended. This action ensures that the remaining train is OPERABLE, that no undetected failures preventing system operation will occur, and that any active failure will be readily detected.

B 3.7 PLANT SYSTEMS

B 3.7.19 Secondary System Isolation Valves (SSIVs)

BASES

BACKGROUND

Closure of secondary system isolation valves (SSIVs) ensures that the assumptions used in the plant accident and containment analyses remain valid. In accident conditions, SSIVs close to terminate the blowdown from the faulted steam generator and isolate the intact steam generators, and to isolate the plant secondary side in order to prevent possible diversion of auxiliary feedwater flow.

The accident analyses assume that the steam generators are isolated after receiving an isolation signal. Following receipt of the steam line isolation signal (SLIS) and auxiliary feedwater actuation signal (AFAS), the intact steam generators are assumed to be isolated, except for the steam supply valves to the turbine-driven auxiliary feedwater pump (governed by LCO 3.7.5, "Auxiliary Feedwater (AFW) System"). There are also analysis cases that evaluate the single failure of a main steam or main feedwater isolation valve. In addition to the valves governed by LCO 3.7.2, "Main Steam Isolation Valves (MSIVs) and MSIV Valve Bypass Valves," and LCO 3.7.3, "Main Feedwater Isolation Valves (MFIVs) and Main Feedwater Regulating Valves (MFRVs) and MFRV Bypass Valves," the analysis assumptions require that the steam generator blowdown and sample line isolation valves are closed.

When plant accident conditions require delivery of auxiliary feedwater, the normally closed steam supply isolation valves to the turbine-driven auxiliary feedwater pump (TDAFP) open on an AFAS. This ensures availability of the TDAFP. The AFAS also closes the steam generator blowdown and sample isolation valves in order to isolate the plant's secondary side.

The Steam Generator Blowdown System (SGBS) helps to maintain the steam generator secondary side water within chemical specifications. Heat is recovered from the blowdown and returned to the feedwater system. Portions of the SGBS are safety related and are required to function following a design basis accident.

One blowdown isolation valve (SGBIV) is installed in each of the four blowdown lines outside the containment. These valves prevent uncontrolled blowdown from more than one steam generator and isolate non-safety related portions from the safety related portions of the system. These valves are air-operated globe valves which fail closed. For

BASES

BACKROUND (continued)

emergency closure, either of two safety related solenoid valves is de-energized to dump air supplied to the valve actuator. The electrical solenoid valves are energized from separate Class 1E sources and are closed upon receipt of an steam generator blowdown and sample isolation (AFAS) signal.

The SGBS also includes safety related steam generator blowdown sample isolation valves (SGBSIVs). Three SGBSIVs are installed in each of the sample line flow paths for each steam generator. Two valves are located inside the containment (one from each sample point), and one valve is located outside containment. The SGBSIVs prevent uncontrolled blowdown from more than one steam generator and isolate the non-safety related portions from the safety related portions of the system. The SGBSIVs are solenoid-operated globe valves which fail closed. The inside containment solenoid valves are energized from separate Class IE sources from the outside containment solenoid valves. These valves are also closed upon receipt of an steam generator blowdown and sample isolation (AFAS) signal.

The main steam and related secondary side lines are automatically isolated upon receipt of an SLIS or feedwater isolation signal (FWIS). The diverse parameters sensed to initiate an SLIS are low steam line pressure, high negative steam pressure rate, and high containment pressure (Hi-2).

A FWIS is generated by a safety injection signal (SIS), reactor trip with low Tave, steam generator water level high-high, or steam generator water level low-low. The diverse parameters sensed to initiate an SIS are low steam line pressure, low pressurizer pressure, and high containment pressure (Hi-1).

Descriptions of SSIVs are found in the USAR, Section 10.4.7 (Ref. 1), Section 10.4.8 (Ref. 2), and Section 10.3 (Ref. 3).

APPLICABLE SAFETY ANALYSES

The accident analysis assume that the steam generators are isolated after receiving an isolation signal as discussed in the Background section. Further discussion can be found in the USAR, Chapters 6 and 15.

The SSIVs function to ensure the primary success path for steam line and feed line isolation and for delivery of required auxiliary feedwater flow and, therefore, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO provides assurance that SSIVs will isolate the plant's secondary side, following a main feed line or main steam line break and ensures the required flow of auxiliary feedwater to the intact steam generators. Secondary system isolation valves are considered OPERABLE when their isolation times are within limits and they are capable of closing on an isolation actuation signal.

Secondary system isolation valves include the SGBIVs (BMHV0001, BMHV0002, BMHV0003, and BMHV0004) and the SGBSIVs (BMHV0019, BMHV0020, BMHV0021, BMHV0022, BMHV0065, BMHV0066, BMHV0067, BMHV0068, BMHV0035, BMHV0036, BMHV0037, and BMHV0038).

APPLICABILITY

The SSIVs must be OPERABLE in MODES 1, 2, and 3, when there is significant mass and energy in the Reactor Coolant System (RCS) and steam generators. When the SSIVs are closed and de-activated, or closed and isolated by a closed manual valve, or the flow path is isolated by a combination of closed manual valve(s) and closed de-activated automatic valve(s), they are performing the specified safety function of isolating the plant's secondary side.

In MODES 4, 5, and 6, the steam generator energy is low. Therefore, the SSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

The ACTIONS are modified by a Note to provide clarification that, for this LCO, separate Condition entry is allowed for each SSIV. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SSIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SSIVs are governed by subsequent Condition entry and application of associated Required Actions.

A second Note has been added to allow SSIVs to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the SSIV can be rapidly isolated when the need for secondary system isolation is indicated.

BASES

ACTIONS (continued)

A.1 and A.2

With one or more SSIVs inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable valves within 7 days. When these valves are closed or isolated, they are performing their specified safety function.

The 7 day Completion Time takes into account the low probability of an event occurring during this time period that would require isolation of the plant's secondary side. The 7 day Completion Time is reasonable, based on operating experience.

Inoperable SSIVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the accident analyses remain valid. The 7 day Completion Time is reasonable based on engineering judgment, in view of valve status indications in the control room, and other administrative controls, to ensure that these valves are in the closed position or isolated.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.19.1

This SR verifies the proper alignment for required automatic SSIVs in the flow path that are used to isolate the plant's secondary side. The SSIV is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown (which may include the use of local or remote indicators), that valves capable of being mispositioned are in the correct position.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.19.2

This SR verifies that the isolation time of each required automatic SSIV is within limits when tested pursuant to the Inservice Testing Program. The specific limits are documented in the Inservice Testing Program. The SSIV isolation times are less than or equal to those assumed in the accident and containment analyses. The SR is performed only for required SSIVs. An exception is made for the steam generator chemical addition injection isolation valves which are not included in the Inservice Testing Program. These valves are passive, with multiple isolation valves in their flow path.

For the required SSIVs, performance of this Surveillance is routinely done during plant operation (or as required for post-maintenance testing), but it may also be required to be performed upon returning the unit to operation following a refueling outage.

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

SR 3.7.19.3

This SR verifies that each required automatic SSIV in the flow path is capable of closure on an actual or simulated actuation signal. This Surveillance is routinely performed during plant operation, but may also be performed upon returning the unit to operation following a refueling outage.

The Frequency for this SR is 18 months.

REFERENCES

1. USAR, Section 10.4.7.

2. USAR, Section 10.4.8.

3. USAR, Section 10.3.

BASES

ACTIONS

B.2 (continued)

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other train (Train A or Train B) is inoperable and not in the safeguards position.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 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.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DG. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, it would be declared inoperable upon discovery and Condition F of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG. Required Action B.3.2 is modified by a Note stating that it is satisfied by the automatic start and sequence loading of the DG. The Note indicates that an additional start of the DG for test purposes only, is not required if the DG has automatically started and loaded following a loss of the offsite power source to its respective bus (Ref. 18).

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action 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. 7), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

B.4.1, B.4.2.1, and B.4.2.2

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. With a DG inoperable, the inoperable DG must be restored to OPERABLE status within the applicable, specified Completion Time.

The Completion Time of 72 hours for Required Action B.4.1 applies when a DG is discovered or determined to be inoperable, such as due to a component or test failure, and requires time to effect repairs, or it may apply when a DG is rendered inoperable for the performance of maintenance during applicable MODES. The 72-hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA during this period.

The second Completion Time for Required Action B.4.1 also establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable, the LCO may already have been not met for up to 72 hours. If the offsite circuit is restored to OPERABLE status within the required 72 hours, this could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the compliance with the LCO (i.e., restore the DG). At this time, an offsite circuit could again become inoperable and an additional 72 hours allowed prior to complete

B 3.9 REFUELING OPERATIONS

B 3.9.6 Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level

BASES

BACKGROUND	The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchangers where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass lines. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.
APPLICABLE SAFETY ANALYSES	If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the subsequent plate out of boron will eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Two trains of the RHR System are required to be OPERABLE, and one train in operation, in order to prevent this challenge. Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in 10 CFR 50.36(c)(2)(ii) as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.
LCO	In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, both RHR loops must be OPERABLE. Additionally, one loop of RHR must be in operation in order to provide: a. Removal of decay heat; b. Mixing of borated coolant to minimize the possibility of criticality; and

BASES

LCO (continued)

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path and to determine the RCS temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. An OPERABLE RHR loop must be capable of being realigned to provide an OPERABLE flow path.

When both RHR loops (or trains) are required to be OPERABLE, the associated Component Cooling Water (CCW) train is required to be OPERABLE. The heat sink for the CCW System is normally provided by the Service Water System or Essential Service Water (ESW) System, as determined by system availability. In MODES 5 and 6, one Diesel Generator (DG) is required to be OPERABLE per LCO 3.8.2, "AC Sources – Shutdown." The same ESW train is required to be OPERABLE to support DG OPERABILITY. Typically, both ESW trains are utilized to support CCW train OPERABILITY. However, a Service Water train can be utilized to support CCW/RHR OPERABILITY if the associated ESW train is inoperable.

APPLICABILITY

Two RHR loops are required to be OPERABLE, and one RHR loop must be in operation in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, to provide decay heat removal. Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). RHR loop requirements in MODE 6 with the water level ≥ 23 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level."

Since LCO 3.9.6 contains Required Actions with immediate Completion Times related to the restoration of the degraded decay heat removal function, it is not permitted to enter this LCO from either MODE 5 or from LCO 3.9.5, "RHR and Coolant Circulation – High Water Level," unless the requirements of LCO 3.9.6 are met. This precludes diminishing the backup decay heat removal capability when the RHR System is degraded.

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, action shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and to operation in accordance with the LCO or until ≥ 23 ft of water level is established above the reactor

BASES

ACTIONS

A.1 and A.2 (continued)

vessel flange. When the water level is ≥ 23 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.5, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

B.1

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit of LCO 3.9.1 is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

B.2

If no RHR loop is in operation, actions shall be initiated immediately, and continued, to restore one RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

B.3

If no RHR loop is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures that dose limits are not exceeded.

The Completion Time of 4 hours is reasonable at water levels above reduced inventory, based on the low probability of the coolant boiling in that time. At reduced inventory conditions, additional actions are taken to provide containment closure in a reduced period of time (Reference 2). Reduced inventory is defined as RCS level lower than 3 feet below the reactor vessel.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control,and alarm indications available to the operator for monitoring the RHR System in the control room.

SR 3.9.6.2

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

1. USAR, Section 5.4.7.

2. Generic Letter No. 88-17, "Loss of Decay Heat Removal."

PAGE (1)	REVISION NO. (2)	CHANGE DOCUMENT (3)	DATE EFFECTIVE/ IMPLEMENTED (4)
TAB – Title Page Technical Specification			
Cover Page			
Title Page			
TAB – Table of Contents			
i	34	DRR 07-1057	7/10/07
ii	29	DRR 06-1984	10/17/06
iii	44	DRR 09-1744	10/28/09
TAB – B 2.0 SAFETY LIMITS (SLs)			
B 2.1.1-1	0	Amend. No. 123	12/18/99
B 2.1.1-2	14	DRR 03-0102	2/12/03
B 2.1.1-3	14	DRR 03-0102	2/12/03
B 2.1.1-4	0	Amend. No. 123	2/12/03
B 2.1.2-1	0	Amend. No. 123	12/18/99
B 2.1.2-2	12	DRR 02-1062	9/26/02
B 2.1.2-3	0	Amend. No. 123	12/18/99
TAB – B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILTY			
B 3.0-1	34	DRR 07-1057	7/10/07
B 3.0-2	0	Amend. No. 123	12/18/99
B 3.0-3	0	Amend. No. 123	12/18/99
B 3.0-4	19	DRR 04-1414	10/12/04
B 3.0-5	19	DRR 04-1414	10/12/04
B 3.0-6	19	DRR 04-1414	10/12/04
B 3.0-7	19	DRR 04-1414	10/12/04
B 3.0-8	19	DRR 04-1414	10/12/04
B 3.0-9	42	DRR 09-1009	7/16/09
B 3.0-10	42	DRR 09-1009	7/16/09
B 3.0-11	34	DRR 07-1057	7/10/07
B 3.0-12	34	DRR 07-1057	7/10/07
B 3.0-13	34	DRR 07-1057	7/10/07
B 3.0-14	34	DRR 07-1057	7/10/07
B 3.0-15	34	DRR 07-1057	7/10/07
B 3.0-16	34	DRR 07-1057	7/10/07
TAB – B 3.1 REACTIVITY CONTROL SYSTEMS			
B 3.1.1-1	0	Amend. No. 123	12/18/99
B 3.1.1-2	0	Amend. No. 123	12/18/99
B 3.1.1-3	0	Amend. No. 123	12/18/99
B 3.1.1-4	19	DRR 04-1414	10/12/04
B 3.1.1-5	0	Amend. No. 123	12/18/99
B 3.1.2-1	0	Amend. No. 123	12/18/99
B 3.1.2-2	0	Amend. No. 123	12/18/99
B 3.1.2-3	0	Amend. No. 123	12/18/99
B 3.1.2-4	0	Amend. No. 123	12/18/99
B 3.1.2-5	0	Amend. No. 123	12/18/99
B 3.1.3-1	0	Amend. No. 123	12/18/99
B 3.1.3-2	0	Amend. No. 123	12/18/99
B 3.1.3-3	0	Amend. No. 123	12/18/99
B 3.1.3-4	0	Amend. No. 123	12/18/99

PAGE (1)	REVISION NO. (2)	CHANGE DOCUMENT (3)	DATE EFFECTIVE/ IMPLEMENTED (4)
TAB – B 3.1 REACTIVITY CONTROL SYSTEMS (continued)			
B 3.1.3-5	0	Amend. No. 123	12/18/99
B 3.1.3-6	0	Amend. No. 123	12/18/99
B 3.1.4-1	0	Amend. No. 123	12/18/99
B 3.1.4-2	0	Amend. No. 123	12/18/99
B 3.1.4-3	0	Amend. No. 123	12/18/99
B 3.1.4-4	0	Amend. No. 123	12/18/99
B 3.1.4-5	0	Amend. No. 123	12/18/99
B 3.1.4-6	0	Amend. No. 123	12/18/99
B 3.1.4-7	0	Amend. No. 123	12/18/99
B 3.1.4-8	0	Amend. No. 123	12/18/99
B 3.1.4-9	0	Amend. No. 123	12/18/99
B 3.1.5-1	0	Amend. No. 123	12/18/99
B 3.1.5-2	0	Amend. No. 123	12/18/99
B 3.1.5-3	0	Amend. No. 123	12/18/99
B 3.1.5-4	0	Amend. No. 123	12/18/99
B 3.1.6-1	0	Amend. No. 123	12/18/99
B 3.1.6-2	0	Amend. No. 123	12/18/99
B 3.1.6-3	0	Amend. No. 123	12/18/99
B 3.1.6-4	0	Amend. No. 123	12/18/99
B 3.1.6-5	0	Amend. No. 123	12/18/99
B 3.1.6-6	0	Amend. No. 123	12/18/99
B 3.1.7-1	0	Amend. No. 123	12/18/99
B 3.1.7-2	0	Amend. No. 123	12/18/99
B 3.1.7-3	0	Amend. No. 123	12/18/99
B 3.1.7-4	0	Amend. No. 123	12/18/99
B 3.1.7-5	0	Amend. No. 123	12/18/99
B 3.1.7-6	0	Amend. No. 123	12/18/99
B 3.1.8-1	0	Amend. No. 123	12/18/99
B 3.1.8-2	0	Amend. No. 123	12/18/99
B 3.1.8-3	15	DRR 03-0860	7/10/03
B 3.1.8-4	15	DRR 03-0860	7/10/03
B 3.1.8-5	0	Amend. No. 123	12/18/99
B 3.1.8-6	5	DRR 00-1427	10/12/00
TAB – B 3.2 POWER DISTRIBUTION LIMITS			
B 3.2.1-1	0	Amend. No. 123	12/18/99
B 3.2.1-2	0	Amend. No. 123	12/18/99
B 3.2.1-3	0	Amend. No. 123	12/18/99
B 3.2.1-4	0	Amend. No. 123	12/18/99
B 3.2.1-5	1	DRR 99-1624	12/18/99
B 3.2.1-6	12	DRR 02-1062	9/26/02
B 3.2.1-7	0	Amend. No. 123	12/18/99
B 3.2.1-8	29	DRR 06-1984	10/17/06
B 3.2.1-9	29	DRR 06-1984	10/17/06
B 3.2.1-10	29	DRR 06-1984	10/17/06
B 3.2.2-1	0	Amend. No. 123	12/18/99
B 3.2.2-2	0	Amend. No. 123	12/18/99
B 3.2.2-3	0	Amend. No. 123	12/18/99
B 3.2.2-4	0	Amend. No. 123	12/18/99
B 3.2.2-5	0	Amend. No. 123	12/18/99
B 3.2.2-6	44	DRR 09-1744	10/28/09

PAGE (1)	REVISION NO. (2)	CHANGE DOCUMENT (3)	DATE EFFECTIVE/ IMPLEMENTED (4)
TAB – B 3.2 POWER DISTRIBUTION LIMITS (continued)			
B 3.2.3-1	0	Amend. No. 123	12/18/99
B 3.2.3-2	0	Amend. No. 123	12/18/99
B 3.2.3-3	0	Amend. No. 123	12/18/99
B 3.2.4-1	0	Amend. No. 123	12/18/99
B 3.2.4-2	0	Amend. No. 123	12/18/99
B 3.2.4-3	0	Amend. No. 123	12/18/99
B 3.2.4-4	0	Amend. No. 123	12/18/99
B 3.2.4-5	0	Amend. No. 123	12/18/99
B 3.2.4-6	0	Amend. No. 123	12/18/99
B 3.2.4-7	0	Amend. No. 123	12/18/99
TAB – B 3.3 INSTRUMENTATION			
B 3.3.1-1	0	Amend. No. 123	12/18/99
B 3.3.1-2	0	Amend. No. 123	12/18/99
B 3.3.1-3	0	Amend. No. 123	12/18/99
B 3.3.1-4	0	Amend. No. 123	12/18/99
B 3.3.1-5	0	Amend. No. 123	12/18/99
B 3.3.1-6	0	Amend. No. 123	12/18/99
B 3.3.1-7	5	DRR 00-1427	10/12/00
B 3.3.1-8	0	Amend. No. 123	12/18/99
B 3.3.1-9	0	Amend. No. 123	12/18/99
B 3.3.1-10	29	DRR 06-1984	10/17/06
B 3.3.1-11	0	Amend. No. 123	12/18/99
B 3.3.1-12	0	Amend. No. 123	12/18/99
B 3.3.1-13	0	Amend. No. 123	12/18/99
B 3.3.1-14	0	Amend. No. 123	12/18/99
B 3.3.1-15	0	Amend. No. 123	12/18/99
B 3.3.1-16	0	Amend. No. 123	12/18/99
B 3.3.1-17	0	Amend. No. 123	12/18/99
B 3.3.1-18	0	Amend. No. 123	12/18/99
B 3.3.1-19	0	Amend. No. 123	12/18/99
B 3.3.1-20	0	Amend. No. 123	12/18/99
B 3.3.1-21	0	Amend. No. 123	12/18/99
B 3.3.1-22	0	Amend. No. 123	12/18/99
B 3.3.1-23	9	DRR 02-0123	2/28/02
B 3.3.1-24	0	Amend. No. 123	12/18/99
B 3.3.1-25	0	Amend. No. 123	12/18/99
B 3.3.1-26	0	Amend. No. 123	12/18/99
B 3.3.1-27	0	Amend. No. 123	12/18/99
B 3.3.1-28	2	DRR 00-0147	4/24/00
B 3.3.1-29	1	DRR 99-1624	12/18/99
B 3.3.1-30	1	DRR 99-1624	12/18/99
B 3.3.1-31	0	Amend. No. 123	12/18/99
B 3.3.1-32	20	DRR 04-1533	2/16/05
B 3.3.1-33	20	DRR 04-1533	2/16/05
B 3.3.1-34	20	DRR 04-1533	2/16/05
B 3.3.1-35	19	DRR 04-1414	10/13/04
B 3.3.1-36	20	DRR 04-1533	2/16/05
B 3.3.1-37	20	DRR 04-1533	2/16/05
B 3.3.1-38	20	DRR 04-1533	2/16/05
B 3.3.1-39	25	DRR 06-0800	5/18/06

PAGE [1]	REVISION NO. [2]	CHANGE DOCUMENT [3]	DATE EFFECTIVE/ IMPLEMENTED [4]
TAB – B 3.3 INSTRUMENTATION (continued)			
B 3.3.1-40	20	DRR 04-1533	2/16/05
B 3.3.1-41	20	DRR 04-1533	2/16/05
B 3.3.1-42	20	DRR 04-1533	2/16/05
B 3.3.1-43	20	DRR 04-1533	2/16/05
B 3.3.1-44	20	DRR 04-1533	2/16/05
B 3.3.1-45	20	DRR 04-1533	2/16/05
B 3.3.1-46	20	DRR 04-1533	2/16/05
B 3.3.1-47	20	DRR 04-1533	2/16/05
B 3.3.1-48	20	DRR 04-1533	2/16/05
B 3.3.1-49	20	DRR 04-1533	2/16/05
B 3.3.1-50	20	DRR 04-1533	2/16/05
B 3.3.1-51	21	DRR 05-0707	4/20/05
B 3.3.1-52	20	DRR 04-1533	2/16/05
B 3.3.1-53	20	DRR 04-1533	2/16/05
B 3.3.1-54	20	DRR 04-1533	2/16/05
B 3.3.1-55	25	DRR 06-0800	5/18/06
B 3.3.1-56	20	DRR 04-1533	2/16/05
B 3.3.1-57	20	DRR 04-1533	2/16/05
B 3.3.1-58	29	DRR 06-1984	10/17/06
B 3.3.1-59	20	DRR 04-1533	2/16/05
B 3.3.2-1	0	Amend. No. 123	12/18/99
B 3.3.2-2	0	Amend. No. 123	12/18/99
B 3.3.2-3	0	Amend. No. 123	12/18/99
B 3.3.2-4	0	Amend. No. 123	12/18/99
B 3.3.2-5	0	Amend. No. 123	12/18/99
B 3.3.2-6	7	DRR 01-0474	5/1/01
B 3.3.2-7	0	Amend. No. 123	12/18/99
B 3.3.2-8	0	Amend. No. 123	12/18/99
B 3.3.2-9	0	Amend. No. 123	12/18/99
B 3.3.2-10	0	Amend. No. 123	12/18/99
B 3.3.2-11	0	Amend. No. 123	12/18/99
B 3.3.2-12	0	Amend. No. 123	12/18/99
B 3.3.2-13	0	Amend. No. 123	12/18/99
B 3.3.2-14	2	DRR 00-0147	4/24/00
B 3.3.2-15	0	Amend. No. 123	12/18/99
B 3.3.2-16	0	Amend. No. 123	12/18/99
B 3.3.2-17	0	Amend. No. 123	12/18/99
B 3.3.2-18	0	Amend. No. 123	12/18/99
B 3.3.2-19	37	DRR 08-0503	4/8/08
B 3.3.2-20	37	DRR 08-0503	4/8/08
B 3.3.2-21	37	DRR 08-0503	4/8/08
B 3.3.2-22	37	DRR 08-0503	4/8/08
B 3.3.2-23	37	DRR 08-0503	4/8/08
B 3.3.2-24	39	DRR 08-1096	8/28/08
B 3.3.2-25	39	DRR 08-1096	8/28/08
B 3.3.2-26	39	DRR 08-1096	8/28/08
B 3.3.2-27	37	DRR 08-0503	4/8/08
B 3.3.2-28	37	DRR 08-0503	4/8/08
B 3.3.2-29	0	Amend. No. 123	12/18/99
B 3.3.2-30	0	Amend. No. 123	12/18/99
B 3.3.2-31	0	Amend. No. 123	12/18/99

PAGE [1]	REVISION NO. [2]	CHANGE DOCUMENT [3]	DATE EFFECTIVE/ IMPLEMENTED [4]
TAB – B 3.3 INSTRUMENTATION (continued)			
B 3.3.2-32	0	Amend. No. 123	12/18/99
B 3.3.2-33	0	Amend. No. 123	12/18/99
B 3.3.2-34	0	Amend. No. 123	12/18/99
B 3.3.2-35	20	DRR 04-1533	2/16/05
B 3.3.2-36	20	DRR 04-1533	2/16/05
B 3.3.2-37	20	DRR 04-1533	2/16/05
B 3.3.2-38	20	DRR 04-1533	2/16/05
B 3.3.2-39	25	DRR 06-0800	5/18/06
B 3.3.2-40	20	DRR 04-1533	2/16/05
B 3.3.2-41	37	DRR 08-0503	4/8/08
B 3.3.2-42	20	DRR 04-1533	2/16/05
B 3.3.2-43	20	DRR 04-1533	2/16/05
B 3.3.2-44	20	DRR 04-1533	2/16/05
B 3.3.2-45	20	DRR 04-1533	2/16/05
B 3.3.2-46	20	DRR 04-1533	2/16/05
B 3.3.2-47	43	DRR 09-1416	9/2/09
B 3.3.2-48	37	DRR 08-0503	4/8/08
B 3.3.2-49	20	DRR 04-1533	2/16/05
B 3.3.2-50	20	DRR 04-1533	2/16/05
B 3.3.2-51	43	DRR 09-1416	9/2/09
B 3.3.2-52	43	DRR 09-1416	9/2/09
B 3.3.2-53	43	DRR 09-1416	9/2/09
B 3.3.2-54	43	DRR 09-1416	9/2/09
B 3.3.2-55	43	DRR 09-1416	9/2/09
B 3.3.2-56	43	DRR 09-1416	9/2/09
B 3.3.2-57	43	DRR 09-1416	9/2/09
B 3.3.3-1	0	Amend. No. 123	12/18/99
B 3.3.3-2	5	DRR 00-1427	10/12/00
B 3.3.3-3	0	Amend. No. 123	12/18/99
B 3.3.3-4	0	Amend. No. 123	12/18/99
B 3.3.3-5	0	Amend. No. 123	12/18/99
B 3.3.3-6	8	DRR 01-1235	9/19/01
B 3.3.3-7	21	DRR 05-0707	4/20/05
B 3.3.3-8	8	DRR 01-1235	9/19/01
B 3.3.3-9	8	DRR 01-1235	9/19/01
B 3.3.3-10	19	DRR 04-1414	10/12/04
B 3.3.3-11	19	DRR 04-1414	10/12/04
B 3.3.3-12	21	DRR 05-0707	4/20/05
B 3.3.3-13	21	DRR 05-0707	4/20/05
B 3.3.3-14	8	DRR 01-1235	9/19/01
B 3.3.3-15	8	DRR 01-1235	9/19/01
B 3.3.4-1	0	Amend. No. 123	12/18/99
B 3.3.4-2	9	DRR 02-1023	2/28/02
B 3.3.4-3	15	DRR 03-0860	7/10/03
B 3.3.4-4	19	DRR 04-1414	10/12/04
B 3.3.4-5	1	DRR 99-1624	12/18/99
B 3.3.4-6	9	DRR 02-0123	2/28/02
B 3.3.5-1	0	Amend. No. 123	12/18/99
B 3.3.5-2	1	DRR 99-1624	12/18/99
B 3.3.5-3	1	DRR 99-1624	12/18/99

PAGE [(1)]	REVISION NO. [(2)]	CHANGE DOCUMENT [(3)]	DATE EFFECTIVE/ IMPLEMENTED [(4)]
TAB – B 3.3 INSTRUMENTATION (continued)			
B 3.3.5-4	1	DRR 99-1624	12/18/99
B 3.3.5-5	0	Amend. No. 123	12/18/99
B 3.3.5-6	22	DRR 05-1375	6/28/05
B 3.3.5-7	22	DRR 05-1375	6/28/05
B 3.3.6-1	0	Amend. No. 123	12/18/99
B 3.3.6-2	0	Amend. No. 123	12/18/99
B 3.3.6-3	0	Amend. No. 123	12/18/99
B 3.3.6-4	0	Amend. No. 123	12/18/99
B 3.3.6-5	0	Amend. No. 123	12/18/99
B 3.3.6-6	0	Amend. No. 123	12/18/99
B 3.3.6-7	0	Amend. No. 123	12/18/99
B 3.3.7-1	0	Amend. No. 123	12/18/99
B 3.3.7-2	0	Amend. No. 123	12/18/99
B 3.3.7-3	0	Amend. No. 123	12/18/99
B 3.3.7-4	0	Amend. No. 123	12/18/99
B 3.3.7-5	0	Amend. No. 123	12/18/99
B 3.3.7-6	0	Amend. No. 123	12/18/99
B 3.3.7-7	0	Amend. No. 123	12/18/99
B 3.3.7-8	0	Amend. No. 123	12/18/99
B 3.3.8-1	0	Amend. No. 123	12/18/99
B 3.3.8-2	0	Amend. No. 123	12/18/99
B 3.3.8-3	0	Amend. No. 123	12/18/99
B 3.3.8-4	0	Amend. No. 123	12/18/99
B 3.3.8-5	0	Amend. No. 123	12/18/99
B 3.3.8-6	24	DRR 06-0051	2/28/06
B 3.3.8-7	0	Amend. No. 123	12/18/99
TAB – B 3.4 REACTOR COOLANT SYSTEM (RCS)			
B 3.4.1-1	0	Amend. No. 123	12/18/99
B 3.4.1-2	10	DRR 02-0411	4/5/02
B 3.4.1-3	10	DRR 02-0411	4/5/02
B 3.4.1-4	0	Amend. No. 123	12/18/99
B 3.4.1-5	0	Amend. No. 123	12/18/99
B 3.4.1-6	0	Amend. No. 123	12/18/99
B 3.4.2-1	0	Amend. No. 123	12/18/99
B 3.4.2-2	0	Amend. No. 123	12/18/99
B 3.4.2-3	0	Amend. No. 123	12/18/99
B 3.4.3-1	0	Amend. No. 123	12/18/99
B 3.4.3-2	0	Amend. No. 123	12/18/99
B 3.4.3-3	0	Amend. No. 123	12/18/99
B 3.4.3-4	0	Amend. No. 123	12/18/99
B 3.4.3-5	0	Amend. No. 123	12/18/99
B 3.4.3-6	0	Amend. No. 123	12/18/99
B 3.4.3-7	0	Amend. No. 123	12/18/99
B 3.4.4-1	0	Amend. No. 123	12/18/99
B 3.4.4-2	29	DRR 06-1984	10/17/06
B 3.4.4-3	0	Amend. No. 123	12/18/99
B 3.4.5-1	0	Amend. No. 123	12/18/99
B 3.4.5-2	17	DRR 04-0453	5/26/04
B 3.4.5-3	29	DRR 06-1984	10/17/06
B 3.4.5-4	0	Amend. No. 123	12/18/99

PAGE (1)	REVISION NO. (2)	CHANGE DOCUMENT (3)	DATE EFFECTIVE/ IMPLEMENTED (4)
TAB – B 3.4 REACTOR COOLANT SYSTEM (RCS) (continued)			
B 3.4.5-5	12	DRR 02-1062	9/26/02
B 3.4.5-6	12	DRR 02-1062	9/26/02
B 3.4.6-1	17	DRR 04-0453	5/26/04
B 3.4.6-2	29	DRR 06-1984	10/17/06
B 3.4.6-3	12	DRR 02-1062	9/26/02
B 3.4.6-4	12	DRR 02-1062	9/26/02
B 3.4.6-5	12	DRR 02-1062	9/26/02
B 3.4.7-1	12	DRR 02-1062	9/26/02
B 3.4.7-2	17	DRR 04-0453	5/26/04
B 3.4.7-3	42	DRR 09-1009	7/16/09
B 3.4.7-4	42	DRR 09-1009	7/16/09
B 3.4.7-5	12	DRR 02-1062	9/26/02
B 3.4.8-1	17	DRR 04-0453	5/26/04
B 3.4.8-2	42	DRR 09-1009	7/16/09
B 3.4.8-3	42	DRR 09-1009	7/16/09
B 3.4.8-4	42	DRR 09-1009	7/16/09
B 3.4.9-1	0	Amend. No. 123	12/18/99
B 3.4.9-2	0	Amend. No. 123	12/18/99
B 3.4.9-3	0	Amend. No. 123	12/18/99
B 3.4.9-4	0	Amend. No. 123	12/18/99
B 3.4.10-1	5	DRR 00-1427	10/12/00
B 3.4.10-2	5	DRR 00-1427	10/12/00
B 3.4.10-3	0	Amend. No. 123	12/18/99
B 3.4.10-4	32	DRR 07-0139	2/7/07
B 3.4.11-1	0	Amend. No. 123	12/18/99
B 3.4.11-2	1	DRR 99-1624	12/18/99
B 3.4.11-3	19	DRR 04-1414	10/12/04
B 3.4.11-4	0	Amend. No. 123	12/18/99
B 3.4.11-5	1	DRR 99-1624	12/18/99
B 3.4.11-6	0	Amend. No. 123	12/18/99
B 3.4.11-7	32	DRR 07-0139	2/7/07
B 3.4.12-1	1	DRR 99-1624	12/18/99
B 3.4.12-2	1	DRR 99-1624	12/18/99
B 3.4.12-3	0	Amend. No. 123	12/18/99
B 3.4.12-4	1	DRR 99-1624	12/18/99
B 3.4.12-5	1	DRR 99-1624	12/18/99
B 3.4.12-6	1	DRR 99-1624	12/18/99
B 3.4.12-7	0	Amend. No. 123	12/18/99
B 3.4.12-8	1	DRR 99-1624	12/18/99
B 3.4.12-9	19	DRR 04-1414	10/12/04
B 3.4.12-10	0	Amend. No. 123	12/18/99
B 3.4.12-11	0	Amend. No. 123	12/18/99
B 3.4.12-12	32	DRR 07-0139	2/7/07
B 3.4.12-13	0	Amend. No. 123	12/18/99
B 3.4.12-14	32	DRR 07-0139	2/7/07
B 3.4.13-1	0	Amend. No. 123	12/18/99
B 3.4.13-2	29	DRR 06-1984	10/17/06
B 3.4.13-3	29	DRR 06-1984	10/17/06
B 3.4.13-4	35	DRR 07-1553	9/28/07
B 3.4.13-5	35	DRR 07-1553	9/28/07
B 3.4.13-6	29	DRR 06-1984	10/17/06

PAGE (1)	REVISION NO. (2)	CHANGE DOCUMENT (3)	DATE EFFECTIVE/ IMPLEMENTED (4)
TAB – B 3.4 REACTOR COOLANT SYSTEM (RCS) (continued)			
B 3.4.14-1	0	Amend. No. 123	12/18/99
B 3.4.14-2	0	Amend. No. 123	12/18/99
B 3.4.14-3	0	Amend. No. 123	12/18/99
B 3.4.14-4	0	Amend. No. 123	12/18/99
B 3.4.14-5	32	DRR 07-0139	2/7/07
B 3.4.14-6	32	DRR 07-0139	2/7/07
B 3.4.15-1	31	DRR 06-2494	12/13/06
B 3.4.15-2	31	DRR 06-2494	12/13/06
B 3.4.15-3	33	DRR 07-0656	5/1/07
B 3.4.15-4	33	DRR 07-0656	5/1/07
B 3.4.15-5	31	DRR 06-2494	12/13/06
B 3.4.15-6	31	DRR 06-2494	12/13/06
B 3.4.15-7	31	DRR 06-2494	12/13/06
B 3.4.15-8	31	DRR 06-2494	12/13/06
B 3.4.16-1	31	DRR 06-2494	12/13/06
B 3.4.16-2	31	DRR 06-2494	12/13/06
B 3.4.16-3	31	DRR 06-2494	12/13/06
B 3.4.16-4	31	DRR 06-2494	12/13/06
B 3.4.16-5	31	DRR 06-2494	12/13/06
B 3.4.17-1	29	DRR 06-1984	10/17/06
B 3.4.17-2	44	DRR 09-1744	10/28/09
B 3.4.17-3	29	DRR 06-1984	10/17/06
B 3.4.17-4	29	DRR 06-1984	10/17/06
B 3.4.17-5	29	DRR 06-1984	10/17/06
B 3.4.17-6	29	DRR 06-1984	10/17/06
B 3.4.17-7	44	DRR 09-1744	10/28/09
TAB – B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)			
B 3.5.1-1	0	Amend. No. 123	12/18/99
B 3.5.1-2	0	Amend. No. 123	12/18/99
B 3.5.1-3	0	Amend. No. 123	12/18/99
B 3.5.1-4	0	Amend. No. 123	12/18/99
B 3.5.1-5	1	DRR 99-1624	12/18/99
B 3.5.1-6	1	DRR 99-1624	12/18/99
B 3.5.1-7	16	DRR 03-1497	11/4/03
B 3.5.1-8	1	DRR 99-1624	12/18/99
B 3.5.2-1	0	Amend. No. 123	12/18/99
B 3.5.2-2	0	Amend. No. 123	12/18/99
B 3.5.2-3	0	Amend. No. 123	12/18/99
B 3.5.2-4	0	Amend. No. 123	12/18/99
B 3.5.2-5	41	DRR 09-0288	3/20/09
B 3.5.2-6	42	DRR 09-1009	7/16/09
B 3.5.2-7	42	DRR 09-1009	7/16/09
B 3.5.2-8	38	DRR 08-0624	5/1/08
B 3.5.2-9	38	DRR 08-0624	5/1/08
B 3.5.2-10	41	DRR 09-0288	3/20/09
B 3.5.2-11	41	DRR 09-0288	3/20/09
B 3.5.3-1	16	DRR 03-1497	11/4/03
B 3.5.3-2	19	DRR 04-1414	10/12/04
B 3.5.3-3	19	DRR 04-1414	10/12/04
B 3.5.3-4	16	DRR 03-1497	11/4/03

PAGE [1]	REVISION NO. [2]	CHANGE DOCUMENT [3]	DATE EFFECTIVE/ IMPLEMENTED [4]
TAB – B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) (continued)			
B 3.5.4-1	0	Amend. No. 123	12/18/99
B 3.5.4-2	0	Amend. No. 123	12/18/99
B 3.5.4-3	0	Amend. No. 123	12/18/99
B 3.5.4-4	0	Amend. No. 123	12/18/99
B 3.5.4-5	0	Amend. No. 123	12/18/99
B 3.5.4-6	26	DRR 06-1350	7/24/06
B 3.5.5-1	21	DRR 05-0707	4/20/05
B 3.5.5-2	21	DRR 05-0707	4/20/05
B 3.5.5-3	2	Amend. No. 132	4/24/00
B 3.5.5-4	21	DRR 05-0707	4/20/05
TAB – B 3.6 CONTAINMENT SYSTEMS			
B 3.6.1-1	0	Amend. No. 123	12/18/99
B 3.6.1-2	0	Amend. No. 123	12/18/99
B 3.6.1-3	0	Amend. No. 123	12/18/99
B 3.6.1-4	17	DRR 04-0453	5/26/04
B 3.6.2-1	0	Amend. No. 123	12/18/99
B 3.6.2-2	0	Amend. No. 123	12/18/99
B 3.6.2-3	0	Amend. No. 123	12/18/99
B 3.6.2-4	0	Amend. No. 123	12/18/99
B 3.6.2-5	0	Amend. No. 123	12/18/99
B 3.6.2-6	0	Amend. No. 123	12/18/99
B 3.6.2-7	0	Amend. No. 123	12/18/99
B 3.6.3-1	0	Amend. No. 123	12/18/99
B 3.6.3-2	0	Amend. No. 123	12/18/99
B 3.6.3-3	0	Amend. No. 123	12/18/99
B 3.6.3-4	0	Amend. No. 123	12/18/99
B 3.6.3-5	36	DRR 08-0255	3/11/08
B 3.6.3-6	36	DRR 08-0255	3/11/08
B 3.6.3-7	41	DRR 09-0288	3/20/09
B 3.6.3-8	36	DRR 08-0255	3/11/08
B 3.6.3-9	36	DRR 08-0255	3/11/08
B 3.6.3-10	8	DRR 01-1235	9/19/01
B 3.6.3-11	36	DRR 08-0255	3/11/08
B 3.6.3-12	36	DRR 08-0255	3/11/08
B 3.6.3-13	36	DRR 08-0255	3/11/08
B 3.6.3-14	36	DRR 08-0255	3/11/08
B 3.6.3-15	39	DRR 08-1096	8/28/08
B 3.6.3-16	39	DRR 08-1096	8/28/08
B 3.6.3-17	36	DRR 08-0255	3/11/08
B 3.6.3-18	36	DRR 08-0255	3/11/08
B 3.6.3-19	36	DRR 08-0255	3/11/08
B 3.6.4-1	39	DRR 08-1096	8/28/08
B 3.6.4-2	0	Amend. No. 123	12/18/99
B 3.6.4-3	0	Amend. No. 123	12/18/99
B 3.6.5-1	0	Amend. No. 123	12/18/99
B 3.6.5-2	37	DRR 08-0503	4/8/08
B 3.6.5-3	13	DRR 02-1458	12/03/02
B 3.6.5-4	0	Amend. No. 123	12/18/99
B 3.6.6-1	42	DRR 09-1009	7/16/09
B 3.6.6-2	0	Amend. No. 123	12/18/99

PAGE (1)	REVISION NO. (2)	CHANGE DOCUMENT (3)	DATE EFFECTIVE/ IMPLEMENTED (4)
TAB – B 3.6 CONTAINMENT SYSTEMS (continued)			
B 3.6.6-3	37	DRR 08-0503	4/8/08
B 3.6.6-4	42	DRR 09-1009	7/16/09
B 3.6.6-5	0	Amend. No. 123	12/18/99
B 3.6.6-6	18	DRR 04-1018	9/1/04
B 3.6.6-7	0	Amend. No. 123	12/18/99
B 3.6.6-8	32	DRR 07-0139	2/7/07
B 3.6.6-9	32	DRR 07-0139	2/7/07
B 3.6.7-1	0	Amend. No. 123	12/18/99
B 3.6.7-2	42	DRR 09-1009	7/16/09
B 3.6.7-3	0	Amend. No. 123	12/18/99
B 3.6.7-4	29	DRR 06-1984	10/17/06
B 3.6.7-5	42	DRR 09-1009	7/16/09
TAB – B 3.7 PLANT SYSTEMS			
B 3.7.1-1	0	Amend. No. 123	12/18/99
B 3.7.1-2	0	Amend. No. 123	12/18/99
B 3.7.1-3	0	Amend. No. 123	12/18/99
B 3.7.1-4	0	Amend. No. 123	12/18/99
B 3.7.1-5	32	DRR 07-0139	2/7/07
B 3.7.1-6	32	DRR 07-0139	2/7/07
B 3.7.2-1	44	DRR 09-1744	10/28/09
B 3.7.2-2	44	DRR 09-1744	10/28/09
B 3.7.2-3	44	DRR 09-1744	10/28/09
B 3.7.2-4	44	DRR 09-1744	10/28/09
B 3.7.2-5	44	DRR 09-1744	10/28/09
B 3.7.2-6	44	DRR 09-1744	10/28/09
B 3.7.2-7	44	DRR 09-1744	10/28/09
B 3.7.2-8	44	DRR 09-1744	10/28/09
B 3.7.2-9	44	DRR 09-1744	10/28/09
B 3.7.2-10	44	DRR 09-1744	10/28/09
B 3.7.2-11	44	DRR 09-1744	10/28/09
B 3.7.3-1	37	DRR 08-0503	4/8/08
B 3.7.3-2	38	DRR 08-0624	5/1/08
B 3.7.3-3	37	DRR 08-0503	4/8/08
B 3.7.3-4	37	DRR 08-0503	4/8/08
B 3.7.3-5	37	DRR 08-0503	4/8/08
B 3.7.3-6	37	DRR 08-0503	4/8/08
B 3.7.3-7	37	DRR 08-0503	4/8/08
B 3.7.3-8	37	DRR 08-0503	4/8/08
B 3.7.3-9	37	DRR 08-0503	4/8/08
B 3.7.3-10	38	DRR 08-0624	5/1/08
B 3.7.3-11	37	DRR 08-0503	4/8/08
B 3.7.4-1	1	DRR 99-1624	12/18/99
B 3.7.4-2	1	DRR 99-1624	12/18/99
B 3.7.4-3	19	DRR 04-1414	10/12/04
B 3.7.4-4	19	DRR 04-1414	10/12/04
B 3.7.4-5	1	DRR 99-1624	12/18/99
B 3.7.5-1	0	Amend. No. 123	12/18/99

PAGE [1]	REVISION NO. [2]	CHANGE DOCUMENT [3]	DATE EFFECTIVE/ IMPLEMENTED [4]
TAB – B 3.7 PLANT SYSTEMS (continued)			
B 3.7.5-2	0	Amend. No. 123	12/18/99
B 3.7.5-3	0	Amend. No. 123	12/18/99
B 3.7.5-4	44	DRR 09-1744	10/28/09
B 3.7.5-5	44	DRR 09-1744	10/28/09
B 3.7.5-6	44	DRR 09-1744	10/28/09
B 3.7.5-7	32	DRR 07-0139	2/7/07
B 3.7.5-8	14	DRR 03-0102	2/12/03
B 3.7.5-9	32	DRR 07-0139	2/7/07
B 3.7.6-1	0	Amend. No. 123	12/18/99
B 3.7.6-2	0	Amend. No. 123	12/18/99
B 3.7.6-3	0	Amend. No. 123	12/18/99
B 3.7.7-1	0	Amend. No. 123	12/18/99
B 3.7.7-2	0	Amend. No. 123	12/18/99
B 3.7.7-3	0	Amend. No. 123	12/18/99
B 3.7.7-4	1	DRR 99-1624	12/18/99
B 3.7.8-1	0	Amend. No. 123	12/18/99
B 3.7.8-2	0	Amend. No. 123	12/18/99
B 3.7.8-3	0	Amend. No. 123	12/18/99
B 3.7.8-4	0	Amend. No. 123	12/18/99
B 3.7.8-5	0	Amend. No. 123	12/18/99
B 3.7.9-1	3	Amend. No. 134	7/14/00
B 3.7.9-2	3	Amend. No. 134	7/14/00
B 3.7.9-3	3	Amend. No. 134	7/14/00
B 3.7.9-4	3	Amend. No. 134	7/14/00
B 3.7.10-1	41	DRR 09-0288	3/20/09
B 3.7.10-2	41	DRR 09-0288	3/20/09
B 3.7.10-3	41	DRR 09-0288	3/20/09
B 3.7.10-4	41	DRR 09-0288	3/20/09
B 3.7.10-5	41	DRR 09-0288	3/20/09
B 3.7.10-6	41	DRR 09-0288	3/20/09
B 3.7.10-7	41	DRR 09-0288	3/20/09
B 3.7.10-8	41	DRR 09-0288	3/20/09
B 3.7.10-9	41	DRR 09-0288	3/20/09
B 3.7.11-1	0	Amend. No. 123	12/18/99
B 3.7.11-2	0	Amend. No. 123	12/18/99
B 3.7.11-3	0	Amend. No. 123	12/18/99
B 3.7.11-4	0	Amend. No. 123	12/18/99
B 3.7.12-1	0	Amend. No. 123	12/18/99
B 3.7.13-1	24	DRR 06-0051	2/28/06
B 3.7.13-2	1	DRR 99-1624	12/18/99
B 3.7.13-3	42	DRR 09-1009	7/16/09
B 3.7.13-4	1	DRR 99-1624	12/18/99
B 3.7.13-5	1	DRR 99-1624	12/18/99
B 3.7.13-6	12	DRR 02-1062	9/26/02
B 3.7.13-7	1	DRR 99-1624	12/18/99
B 3.7.13-8	1	DRR 99-1624	12/18/99
B 3.7.14-1	0	Amend. No. 123	12/18/99
B 3.7.15-1	0	Amend. No. 123	12/18/99
B 3.7.15-2	0	Amend. No. 123	12/18/99
B 3.7.15-3	0	Amend. No. 123	12/18/99
B 3.7.16-1	5	DRR 00-1427	10/12/00

PAGE (1)	REVISION NO. (2)	CHANGE DOCUMENT (3)	DATE EFFECTIVE/ IMPLEMENTED (4)
TAB – B 3.7 PLANT SYSTEMS (continued)			
B 3.7.16-2	23	DRR 05-1995	9/28/05
B 3.7.16-3	5	DRR 00-1427	10/12/00
B 3.7.17-1	7	DRR 01-0474	5/1/01
B 3.7.17-2	7	DRR 01-0474	5/1/01
B 3.7.17-3	5	DRR 00-1427	10/12/00
B 3.7.18-1	0	Amend. No. 123	12/18/99
B 3.7.18-2	0	Amend. No. 123	12/18/99
B 3.7.18-3	0	Amend. No. 123	12/18/99
B 3.7.19-1	44	DRR 09-1744	10/28/09
B 3.7.19-2	44	DRR 09-1744	10/28/09
B 3.7.19-3	44	DRR 09-1744	10/28/09
B 3.7.19-4	44	DRR 09-1744	10/28/09
B 3.7.19-5	44	DRR 09-1744	10/28/09
TAB – B 3.8 ELECTRICAL POWER SYSTEMS			
B 3.8.1-1	0	Amend. No. 123	12/18/99
B 3.8.1-2	0	Amend. No. 123	12/18/99
B 3.8.1-3	25	DRR 06-0800	5/18/06
B 3.8.1-4	25	DRR 06-0800	5/18/06
B 3.8.1-5	25	DRR 06-0800	5/18/06
B 3.8.1-6	25	DRR 06-0800	5/18/06
B 3.8.1-7	26	DRR 06-1350	7/24/06
B 3.8.1-8	35	DRR 07-1553	9/28/07
B 3.8.1-9	42	DRR 09-1009	7/16/09
B 3.8.1-10	39	DRR 08-1096	8/28/08
B 3.8.1-11	36	DRR 08-0255	3/11/08
B 3.8.1-12	35	DRR 07-1553	9/28/07
B 3.8.1-13	26	DRR 06-1350	7/24/06
B 3.8.1-14	26	DRR 06-1350	7/24/06
B 3.8.1-15	26	DRR 06-1350	7/24/06
B 3.8.1-16	26	DRR 06-1350	7/24/06
B 3.8.1-17	26	DRR 06-1350	7/24/06
B 3.8.1-18	26	DRR 06-1350	7/24/06
B 3.8.1-19	26	DRR 06-1350	7/24/06
B 3.8.1-20	26	DRR 06-1350	7/24/06
B 3.8.1-21	33	DRR 07-0656	5/1/07
B 3.8.1-22	33	DRR 07-0656	5/1/07
B 3.8.1-23	40	DRR 08-1846	12/9/08
B 3.8.1-24	33	DRR 07-0656	5/1/07
B 3.8.1-25	33	DRR 07-0656	5/1/07
B 3.8.1-26	33	DRR 07-0656	5/1/07
B 3.8.1-27	33	DRR 07-0656	5/1/07
B 3.8.1-28	33	DRR 07-0656	5/1/07
B 3.8.1-29	33	DRR 07-0656	5/1/07
B 3.8.1-30	33	DRR 07-0656	5/1/07
B 3.8.1-31	33	DRR 07-0656	5/1/07
B 3.8.1-32	33	DRR 07-0656	5/1/07
B 3.8.1-33	39	DRR 08-1096	8/28/08
B 3.8.1-34	39	DRR 08-1096	8/28/08
B 3.8.2-1	0	Amend. No. 123	12/18/99
B 3.8.2-2	0	Amend. No. 123	12/18/99

PAGE (1)	REVISION NO. (2)	CHANGE DOCUMENT (3)	DATE EFFECTIVE/ IMPLEMENTED (4)
TAB – B 3.8 ELECTRICAL POWER SYSTEMS (continued)			
B 3.8.2-3	0	Amend. No. 123	12/18/99
B 3.8.2-4	0	Amend. No. 123	12/18/99
B 3.8.2-5	12	DRR 02-1062	9/26/02
B 3.8.2-6	12	DRR 02-1062	9/26/02
B 3.8.2-7	12	DRR 02-1062	9/26/02
B 3.8.3-1	1	DRR 99-1624	12/18/99
B 3.8.3-2	0	Amend. No. 123	12/18/99
B 3.8.3-3	0	Amend. No. 123	12/18/99
B 3.8.3-4	1	DRR 99-1624	12/18/99
B 3.8.3-5	0	Amend. No. 123	12/18/99
B 3.8.3-6	0	Amend. No. 123	12/18/99
B 3.8.3-7	12	DRR 02-1062	9/26/02
B 3.8.3-8	1	DRR 99-1624	12/18/99
B 3.8.3-9	0	Amend. No. 123	12/18/99
B 3.8.4-1	0	Amend. No. 123	12/18/99
B 3.8.4-2	0	Amend. No. 123	12/18/99
B 3.8.4-3	0	Amend. No. 123	12/18/99
B 3.8.4-4	0	Amend. No. 123	12/18/99
B 3.8.4-5	0	Amend. No. 123	12/18/99
B 3.8.4-6	0	Amend. No. 123	12/18/99
B 3.8.4-7	6	DRR 00-1541	3/13/01
B 3.8.4-8	0	Amend. No. 123	12/18/99
B 3.8.4-9	2	DRR 00-0147	4/24/00
B 3.8.5-1	0	Amend. No. 123	12/18/99
B 3.8.5-2	0	Amend. No. 123	12/18/99
B 3.8.5-3	0	Amend. No. 123	12/18/99
B 3.8.5-4	12	DRR 02-1062	9/26/02
B 3.8.5-5	12	DRR 02-1062	9/26/02
B 3.8.6-1	0	Amend. No. 123	12/18/99
B 3.8.6-2	0	Amend. No. 123	12/18/99
B 3.8.6-3	0	Amend. No. 123	12/18/99
B 3.8.6-4	0	Amend. No. 123	12/18/99
B 3.8.6-5	0	Amend. No. 123	12/18/99
B 3.8.6-6	0	Amend. No. 123	12/18/99
B 3.8.7-1	0	Amend. No. 123	12/18/99
B 3.8.7-2	5	DRR 00-1427	10/12/00
B 3.8.7-3	0	Amend. No. 123	12/18/99
B 3.8.7-4	0	Amend. No. 123	12/18/99
B 3.8.8-1	0	Amend. No. 123	12/18/99
B 3.8.8-2	0	Amend. No. 123	12/18/99
B 3.8.8-3	0	Amend. No. 123	12/18/99
B 3.8.8-4	12	DRR 02-1062	9/26/02
B 3.8.8-5	12	DRR 02-1062	9/26/02
B 3.8.9-1	0	Amend. No. 123	12/18/99
B 3.8.9-2	0	Amend. No. 123	12/18/99
B 3.8.9-3	0	Amend. No. 123	12/18/99
B 3.8.9-4	0	Amend. No. 123	12/18/99
B 3.8.9-5	0	Amend. No. 123	12/18/99
B 3.8.9-6	0	Amend. No. 123	12/18/99
B 3.8.9-7	0	Amend. No. 123	12/18/99
B 3.8.9-8	1	DRR 99-1624	12/18/99

PAGE (1)	REVISION NO. (2)	CHANGE DOCUMENT (3)	DATE EFFECTIVE/ IMPLEMENTED (4)
TAB – B 3.8 ELECTRICAL POWER SYSTEMS (continued)			
B 3.8.9-9	0	Amend. No. 123	12/18/99
B 3.8.10-1	0	Amend. No. 123	12/18/99
B 3.8.10-2	0	Amend. No. 123	12/18/99
B 3.8.10-3	0	Amend. No. 123	12/18/99
B 3.8.10-4	0	Amend. No. 123	12/18/99
B 3.8.10-5	12	DRR 02-1062	9/26/02
B 3.8.10-6	12	DRR 02-1062	9/26/02
TAB – B 3.9 REFUELING OPERATIONS			
B 3.9.1-1	0	Amend. No. 123	12/18/99
B 3.9.1-2	19	DRR 04-1414	10/12/04
B 3.9.1-3	19	DRR 04-1414	10/12/04
B 3.9.1-4	19	DRR 04-1414	10/12/04
B 3.9.2-1	0	Amend. No. 123	12/18/99
B 3.9.2-2	0	Amend. No. 123	12/18/99
B 3.9.2-3	0	Amend. No. 123	12/18/99
B 3.9.3-1	24	DRR 06-0051	2/28/06
B 3.9.3-2	24	DRR 06-0051	2/28/06
B 3.9.3-3	24	DRR 06-0051	2/28/06
B 3.9.3-4	24	DRR 06-0051	2/28/06
B 3.9.4-1	23	DRR 05-1995	9/28/05
B 3.9.4-2	13	DRR 02-1458	12/03/02
B 3.9.4-3	25	DRR 06-0800	5/18/06
B 3.9.4-4	23	DRR 05-1995	9/28/05
B 3.9.4-5	33	DRR 07-0656	5/1/07
B 3.9.4-6	23	DRR 05-1995	9/28/05
B 3.9.5-1	0	Amend. No. 123	12/18/99
B 3.9.5-2	32	DRR 07-0139	2/7/07
B 3.9.5-3	32	DRR 07-0139	2/7/07
B 3.9.5-4	32	DRR 07-0139	2/7/07
B 3.9.6-1	0	Amend. No. 123	12/18/99
B 3.9.6-2	42	DRR 09-1009	7/16/09
B 3.9.6-3	42	DRR 09-1009	7/16/09
B 3.9.6-4	42	DRR 09-1009	7/16/09
B 3.9.7-1	25	DRR 06-0800	5/18/06
B 3.9.7-2	0	Amend. No. 123	12/18/99
B 3.9.7-3	0	Amend. No. 123	12/18/99

PAGE [1]	REVISION NO. [2]	CHANGE DOCUMENT [3]	DATE EFFECTIVE/ IMPLEMENTED [4]

Note 1 The page number is listed on the center of the bottom of each page.

Note 2 The revision number is listed in the lower right hand corner of each page. The Revision number will be page specific.

Note 3 The change document will be the document requesting the change. Amendment No. 123 issued the improved Technical Specifications and associated Bases which affected each page. The NRC has indicated that Bases changes will not be issued with License Amendments. Therefore, the change document should be a DRR number in accordance with AP 26A-002.

Note 4 The date effective or implemented is the date the Bases pages are issued by Document Control.