WOLF CREEK
NUCLEAR OPERATING CORPORATION

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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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Subject: Docket 50-482: Wolf Creek Generating Station Changes to Technical Specification Bases – Revisions 6 through 8

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 Bases changes made without prior 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 6 through 8) under the provisions of TS Section 5.5.14 and a List of Effective Pages. This submittal reflects changes from January 1, 2001 through December 31, 2001. There are no commitments contained in this submittal.

If you have any questions concerning this matter, please contact me at (620) 364-4034, or Mr. Tony Harris at (620) 364-4038.

Very truly yours,

Richard A. Muench

RAM/rlr

Enclosure

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A001

Wolf Creek Generating Station

Changes to Technical Specification Bases

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the Overtemperature ΔT Function.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 75% RTP. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to perform flux mapping. The SR is deferred until a scheduled testing plateau above 75% RTP is attained during a power ascension. During a typical power ascension, it is usually necessary to control the axial flux difference at lower power levels through control rod insertion. After equilibrium conditions are achieved at the specified power plateau, a flux map must be taken and the required data collected. The data is typically analyzed and the appropriate excore calibrations completed within 48 hours after achieving equilibrium conditions. An additional time allowance of 24 hours is provided during which the effects of equipment failures may be remedied and any required re-testing may be performed.

The allowance of 72 hours after equilibrium conditions are attained at the testing plateau provides sufficient time to allow power ascensions and associated testing to be conducted in a controlled and orderly manner at conditions that provide acceptable results and without introducing the potential for extended operation at high power levels with instrumentation that has not been verified to be OPERABLE for subsequent use.

The Frequency of 92 EFPD is adequate. It is based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 92 days.

A COT is performed on each required channel to ensure the channel will perform the intended Function.

Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

SR 3.3.1.7 is modified by a Note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3. Note 2 requires that the quarterly COT for the source range instrumentation shall include verification by observation of the associated permissive annunciator window that the P-6 and P-10 interlocks are in their required state for the existing conditions.

The Frequency of 92 days is justified in Reference 6.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, and it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit conditions. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed, e.g., by observation of the associated permissive annunciator window, within 92 days of the Frequencies prior to reactor startup, 12 hours after reducing power below P-10, and four hours after reducing power below P-6. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of "12 hours after reducing power below P-10" (applicable to intermediate and power range low channels) and "4 hours after reducing power below P-6" (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency of every 92 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup, 12 hours after reducing power below P-10, and four hours after reducing power below P-6. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 for more than 12 hours or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 12 hour or the 4 hour limit. These time limits are reasonable, based

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.13 (continued)

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of the Manual Reactor Trip, the SI Input from ESFAS, and the Reactor Trip Bypass Breaker undervoltage trip mechanisms. This TADOT is performed every 18 months. The Manual Reactor Trip TADOT shall independently verify the OPERABILITY of the handswitch undervoltage and shunt trip contacts for both the Reactor Trip Breakers and Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip mechanism.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The Functions affected have no setpoints associated with them.

SR 3.3.1.15

SR 3.3.1.15 is the performance of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, except that this test is performed prior to exceeding the P-9 interlock whenever the unit has been in MODE 3. This Surveillance is not required if it has been performed within the previous 31 days. Verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to exceeding the P-9 interlock.

SR 3.3.1.16

SR 3.3.1.16 verifies that the individual channel actuation response times are less than or equal to the maximum values assumed in the accident analysis. Response time testing acceptance criteria are included in Table B 3.3.1-2. No credit was taken in the safety analyses for those

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.16 (continued)

channels with response times listed as N.A. No response time testing requirements apply where N.A. is listed in Table B 3.3.1-2. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor until loss of stationary gripper coil voltage.

For channels that include dynamic transfer Functions (e.g., lag, lead/lag, rate/lag, etc.), the response time verification is performed with the time constants set at their nominal values. The response time may be measured by a series of overlapping tests, or other verification (e.g., Ref. 7), such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated response times with actual response time tests on the remainder of the channel. Allocations for response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) inplace, onsite, or offsite (e.g. vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" (Ref. 7), provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

The allocations for sensor response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. One example where response time could be affected is replacing the sensing assembly of a transmitter.

As appropriate, each channel's response time must be verified every 18 months on a STAGGERED TEST BASIS. Each verification shall include at least one train such that both trains are verified at least once per 36 months. Testing of the final actuation devices is included in the verification. Response times cannot be determined during unit operation because equipment operation is required to measure response times. Experience has shown that these components usually pass this

BASES

BACKGROUND

Solid State Protection System (continued)

master relays energizes the relay, which then operates the contacts and applies a low voltage to the associated slave relays. The low voltage is not sufficient to actuate the slave relays but only demonstrates signal path continuity. The SLAVE RELAY TEST actuates the devices if their operation will not interfere with continued unit operation. For devices that will interfere with continued unit operation, actual component operation is prevented, and slave relay contact operation is verified by a continuity check.

Balance of Plant Engineered Safety Feature Actuation System (BOP ESFAS)

The BOP ESFAS processes signals from SSPS, signal processing equipment and plant radiation monitors to actuate certain ESF equipment. There are two redundant trains of BOP ESFAS, and a third separation group to actuate the turbine driven auxiliary feedwater pump. The redundant trains provide actuation for Auxiliary Feedwater Actuation (motor driven pumps), Containment Purge Isolation, Control Room Emergency Ventilation, and Emergency Exhaust Actutation functions.

The BOP ESFAS has a built-in automatic test insertion (ATI) feature which continuously tests the system logic. Any fault detected during the testing causes an alarm on the main control room overhead annunciator system to alert operators to the problem. Local indications show the test step where the fault was detected.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure - Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and two-out-of-four logic configurations allow one channel to be tripped for maintenance or surveillance testing without causing a reactor trip. In cases where an inoperable channel is placed in the tripped condition indefinitely to satisfy the Required Action of an LCO the logic configurations are reduced to one-out-of-two and one-out-of three where tripping of an additional channel, for any reason, would result in a reactor trip. To allow for surveillance testing or setpoint adjustment of other channels while in this condition, several Required Actions allow the inoperable channel to be bypassed. Bypassing the inoperable channel creates a two-out-of-two or two-out-of-three logic configuration allowing a channel to be tripped for testing without causing a reactor trip. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents. ESFAS protection functions are as follows:

1. <u>Safety Injection</u>

   Safety Injection (SI) provides two primary functions:

   1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F); and

   2. Boration to ensure recovery and maintenance of SDM (k_{eff} < 1.0).

   These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Auxiliary Feedwater (continued)

driven AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level - Low Low in any two operating SGs will cause the turbine driven pump to start. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

g. Auxiliary Feedwater - Trip of All Main Feedwater Pumps

A Trip of all MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. Each turbine driven MFW pump is equipped with two pressure switches (one in separation group 1 and one in separation group 4) on the oil line for the speed control system. A low pressure signal from either of these pressure switches indicates a trip of that pump. Two OPERABLE channels per pump satisfy redundancy requirements with one-out-of-two logic on both pumps required for signal activation. A trip of all MFW pumps starts the motor driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

Function 6.g must be OPERABLE in MODE 1. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of an accident. In MODE 2, AFW actuation due to a trip of all MFW pumps is normally blocked. Blocking of this trip function is permitted just before shutdown of the last operating main feedwater pump and the restoration of this trip function just after the first main feedwater pump is put into service following SR 3.3.2.8. This limits the potential for inadvertent AFW actuations during normal startups and shutdowns. In MODES 3, 4, and 5, the MFW pumps may be normally shut down, and thus pump trip is not indicative of a condition requiring automatic AFW initiation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

h. Auxiliary Feedwater - Pump Suction Transfer on Suction Pressure - Low

A low pressure signal in the AFW pump suction line protects the AFW pumps against a loss of the normal supply of water for the pumps, the CST. Three pressure switches are located on the AFW pump suction line from the CST. A low pressure signal sensed by any two of the three switches coincident with an auxiliary feedwater actuation signal will cause the emergency supply of water for both pumps to be aligned. ESW (safety grade) is automatically lined up to supply the AFW pumps to ensure an adequate supply of water for the AFW System to maintain at least one of the SGs as the heat sink for reactor decay heat and sensible heat removal.

Since the detectors are located in an area not affected by HELBs or high radiation, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties. The Trip Setpoint is ≥ 21.60 psia.

This Function must be OPERABLE in MODES 1, 2, and 3 to ensure a safety grade supply of water for the AFW System to maintain the SGs as the heat sink for the reactor. This Function does not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW automatic suction transfer does not need to be OPERABLE because RHR will already be in operation, or sufficient time is available to place RHR in operation, to remove decay heat.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.9 (continued)

The Frequency of 18 months is based on the assumed calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

This SR is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. This does not include verification of time delay relays. These are verified by response time testing per SR 3.3.2.10.

SR 3.3.2.10

This SR verifies the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response Time verification acceptance criteria are included in Table B 3.3.2-2. Table B 3.3.2-2 format is based on the initiating trip signal. No credit was taken in the safety analyses for those channels with response times listed as N.A. No response time testing requirements apply where N.A. is listed in Table B 3.3.2-2. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Trip Setpoint value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position).

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time verification is performed with the time constants set at their nominal values. The response time may be verified by a series of overlapping tests, or other verification (e.g., Ref. 8), such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) inplace, onsite, or offsite (e.g. vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" (Ref. 7), provides the basis and methodology for using allocated sensor

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.10 (continued)

response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

The allocations for sensor response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. One example where response time could be affected is replacing the sensing assembly of a transmitter.

ESF response times specified in Table B 3.3.2-2 which include sequential operation of RWST and VCT valves (Notes 3 and 4) are based on values assumed in the non-LOCA safety analyses. These analyses take credit for injection of borated water from the RWST. Injection of borated water is assumed not to occur until the VCT charging pump suction valves are closed following opening of the RWST charging pump suction valves. When the sequential operation of the RWST and VCT valves is not included in the response times (Note 7), the values specified are based on the LOCA analyses. The LOCA analyses take credit for injection flow regardless of the source. Verification of the response times specified in Table B 3.3.2-2 will assure that the assumptions used for the LOCA and non-LOCA analyses with respect to the operation of the VCT and RWST valves are valid.

ESF RESPONSE TIME verification is performed on an 18 month STAGGERED TEST BASIS. Each verification shall include at least one train such that both trains are verified at least once per 36 months. Testing of the final actuation devices, which make up the bulk of the 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.

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)	$\leq 29^{(7)}/27^{(4)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 7
3) Phase "A" Isolation	$\leq 1.5^{(5)}$
4) Auxiliary Feedwater	≤ 60
5) Essential Service Water	$\leq 60^{(1)}$
6) Containment Cooling	$\leq 60^{(1)}$
7) Component Cooling Water	N.A.
8) Emergency Diesel Generators	$\leq 14^{(6)}$
9) Turbine Trip	N.A.
3. Pressurizer Pressure - Low	
a. Safety Injection (ECCS)	$\leq 29^{(7)}/27^{(4)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 7
3) Phase "A" Isolation	$\leq 2^{(5)}$
4) Auxiliary Feedwater	≤ 60
5) Essential Service Water	$\leq 60^{(1)}$
6) Containment Cooling	$\leq 60^{(1)}$
7) Component Cooling Water	N.A.
8) Emergency Diesel Generators	$\leq 14^{(6)}$
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	≤ 7
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	≤ 7
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	$\leq 60^{(1)}$
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

4. Reactor Coolant System Pressure (Wide Range) (continued)

In addition to these verifications, RCS pressure is used for determining RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS pressure can also be used:

- to determine whether to terminate actuated SI or to reinitiate stopped SI;
- to determine when to reset SI and shut off low head SI;
- to manually restart low head SI;
- as reactor coolant pump (RCP) trip criteria; and
- to make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS subcooling margin is also used for unit stabilization and cooldown control.

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

A final use of RCS pressure is to determine whether to operate the pressurizer heaters.

RCS pressure is a Type A variable because the operator uses this indication to monitor the cooldown of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this indication. Furthermore, RCS pressure is one factor that may be used in decisions to terminate RCP operation.

BASES

LCO (continued)

5. Reactor Vessel Water Level Indicating System (RVLIS)

Reactor Vessel Water Level is a Category 1 variable provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy.

The Reactor Vessel Level Indicating System (RVLIS) provides an indication of reactor vessel level from the bottom of the reactor vessel to the top of the reactor during natural circulation conditions and an indication of reactor core and internals pressure drop for any combination of operating RCPs. The RVLIS consists of four reactor vessel water level indicators (BB LI-1311, BB LI-1312, BB LI-1321, and BB LI-1322). The four level indicators are divided into two separate trains; each includes a narrow range and wide range indication. Train A includes indicators BB LI-1311 (narrow range) and BB LI-1312 (wide range). Train B includes indicator BB LI-1321 (narrow range) and BB LI-1322 (wide range). For the purposes of this Specification, a channel is considered a train. A channel is considered OPERABLE when both its narrow range and wide range indicators are OPERABLE (Ref. 10).

6. Containment Normal Sump Water Level

Containment Normal Sump Water Level is a Type A, Category 1 variable provided for verification and long term surveillance of RCS integrity.

Containment Normal Sump Water Level is used for event identification.

7. Containment Pressure (Normal Range)

Containment Pressure (Normal Range) is a Type A, Category 1 variable provided for verification of RCS and containment OPERABILITY.

Containment pressure is used to verify whether closure of main steam isolation valves (MSIVs) is required (at High-2) and whether containment spray and Phase B isolation are required when High-3 containment pressure is reached.

BASES

LCO (continued)

8. Steam Line Pressure

Steam Line Pressure is a Type A, Category 1 variable for event diagnosis, natural circulation, and RCP trip criteria. It is a variable for determining if a secondary pipe rupture has occurred. This indication is provided to aid the operator in determining the faulted steam generator and to verify natural circulation.

9. Containment Radiation Level (High Range, GT-RIC-59, -60)

Containment Radiation Level is a Type A, Category 1 variable provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Containment radiation level is used to determine if a high energy line break (HELB) has occurred, and whether the event is inside or outside of containment.

10. Containment Hydrogen Concentration Level

Hydrogen analyzers are Category 1 variables provided to detect high hydrogen concentration conditions that represent a potential for containment breach from a hydrogen explosion. This variable is also important in verifying the adequacy of mitigating actions.

11. Pressurizer Water Level

Pressurizer Water Level is a Type A, Category 1 variable used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition.

12. Steam Generator Water Level (Wide Range)

SG Water Level (Wide Range) is a Category 1 variable provided to monitor SG dryout and as a criterion for establishing feed and bleed cooling of the RCS. The wide range level indicator for each steam generator is located in the main control room. Wide range steam generator level measurement meets the intent of the single failure criterion for Category 1 variables by virtue of independent diverse variables. In the emergency procedures, auxiliary feedwater (AFW) flow, reactor coolant pressure, and reactor coolant temperature indications are diverse variables which are

BASES

LCO

12. Steam Generator Water Level (Wide Range) (continued)

used to determine whether adequate core cooling is provided in the absence of wide range level indication for a steam generator. The design limitation of having one wide range level indicator in conjunction with one AFW flow indicator per steam generator is consistent with NUREG-0737, Item II.E.1.2 (Reference 8). Wide range steam generator level is not a Type A variable.

SG Water Level (Wide Range) is used to:

- verify that the intact SGs are an adequate heat sink for the reactor;
- determine the nature of the accident in progress (e.g., verify SGTR overfill); and
- verify unit conditions for termination of SI during secondary unit HELBs outside containment.

13. Steam Generator Water Level (Narrow Range)

Steam Generator Water Level (Narrow Range) is a Type A, Category 1 variable for Steam Generator Tube Rupture event diagnosis and SI termination.

SG Water Level (Narrow Range) is used to:

- identify the affected SG following a tube rupture;
- determine the nature of the accident in progress (e.g., verify an SGTR); and
- verify unit conditions for termination of SI during secondary unit HELBs outside containment.

14, 15, 16, 17. Core Exit Temperature

Core exit temperature is a Category 1 variable which provides for verification and long term surveillance of core cooling.

An evaluation was made in support of Reference 2 of the minimum number of valid core exit thermocouples (CET) necessary for measuring core cooling. The evaluation determined the reduced complement of CETs necessary to detect initial core recovery and

BASES

LCO 14, 15, 16, 17. Core Exit Temperature (continued)

trend the ensuing core heatup. The evaluations account for core nonuniformities, including incore effects of the radial decay power distribution, excore effects of condensate runback in the hot legs, and nonuniform inlet temperatures. Based on these evaluations, adequate core cooling is ensured with two valid core exit temperature channels per quadrant with two CETs per required channel. The CET pairs are oriented radially to permit evaluation of core radial decay power distribution. Core exit temperature is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Core exit temperature is also used for unit stabilization and cooldown control.

Two OPERABLE channels of core exit temperature are required in each quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core. Reference 6 discusses the conformance of the thermocouple/core cooling monitoring system to NUREG-0737, Section II.F.2, approved by the NRC in Reference 7. Two sets of two thermocouples ensure a single failure will not disable the ability to determine the radial temperature gradient.

18. Auxiliary Feedwater Flow Rate

AFW Flow Rate is a Category 2 variable provided to monitor operation of decay heat removal via the SGs. The AFW Flow rate indicator for each SG is located in the main control room. Each of the four flow indicators is powered by a different separation group. Since only two of four SGs are required to establish a heat sink for the RCS, flow indication to at least two intact SGs is assured even if a single failure is assumed. AFW flow rate indication is not a Type A variable nor is it Regulatory Guide 1.97 Category 1. (Reference 9).

The AFW Flow to each SG is determined from a differential pressure measurement calibrated for a range of 0 gpm to 400 gpm. Each differential pressure transmitter provides an input to a control room indicator and the unit computer. Since the primary indication used by the operator during an accident is the control room indicator, the PAM specification deals specifically with this portion of the instrument channel.

AFW flow is used three ways:

BASES

LCO

18. Auxiliary Feedwater Flow Rate (continued)

- to verify delivery of AFW flow to the SGs;
- to determine whether to terminate SI if still in progress, in conjunction with SG water level (narrow range); and
- to regulate AFW flow so that the SG tubes remain covered.

AFW flow is also used by the operator to verify that the AFW System is delivering the correct flow to each SG. However, the primary indication used by the operator to ensure an adequate inventory is SG level.

19. Refueling Water Storage Tank (RWST) Level

Refueling Water Storage Tank Level is a Type A, Category 2 variable for determining switchover of containment spray to the containment recirculation sumps. This level indication is provided for the operators to assist in monitoring and ensuring an adequate supply of water for safety injection and containment spray. Table 2 of Reference 2 requires all plant-specific Type A variables to meet Category 1 design and qualification criteria; however, RWST Level is specifically identified in that same table as a Type D Category 2 variable. In this specific case, as discussed in Sections 7.A.3.1 and 7A.3.6 of Reference 1, the requirements of Category 1 are met.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2 and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2 and 3. In MODES 4, 5 and 6, unit conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

Note 1 has been added in the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require unit shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to respond to an accident using alternate instruments and methods, and the low probability of an event requiring these instruments.

BASES

ACTIONS (continued)

Note 2 has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function. When the Required Channels in Table 3.3.3-1 are specified on a per SG basis, then the Condition may be entered separately for each SG.

A.1

Condition A applies when one or more Functions have one required channel that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.6.8, which requires a written report to be submitted to the NRC within the following 14 days. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

C.1

Condition C applies when one or more Functions have two or more inoperable required channels (i.e., two or more channels inoperable in the same Function). Required Action C.1 requires restoring all but one channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two or more required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance

BASES

ACTIONS (continued)

C.1 (continued)

qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of all but one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur. Condition C is modified by a Note that excludes hydrogen analyzer channels.

D.1

Condition D applies when two hydrogen analyzer channels are inoperable. Required Action D.1 requires restoring one hydrogen analyzer channel to OPERABLE status within 72 hours. The 72 hour Completion Time is reasonable based on the unlikely event that a LOCA (which would cause core damage) would occur during this time.

E.1

Condition E applies when the Required Action and associated Completion Time of Condition C or D are not met. Required Action E.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C or D, and the associated Completion Time has expired, Condition E is entered for that channel and provides for transfer to the appropriate subsequent Condition.

F.1 and F.2

If the Required Action and associated Completion Time of Conditions C or D are not met and Table 3.3.3-1 directs entry into Condition F, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least 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 unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS (continued)

G.1

Alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed. These alternate means may be temporarily used if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, in the Administrative Controls section of the TS. Monitoring the core exit thermocouples, pressurizer level indication (BB-LI-0459A, -0460A, or -0461) and RCS subcooling monitor indication (BB-TI-1390A or B) provide an alternate means for RVLIS. These 3 parameters provide diverse information to verify there is adequate core cooling. When Containment Radiation Level (High Range) monitors are inoperable, portable survey equipment with the capability to detect gamma radiation over the range 1E-03 to 1E04 provides an alternate means (Ref. 5).

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.3.2

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 measure parameter with the necessary range and accuracy. This SR is modified by a Note that excludes neutron detectors. Containment Radiation Level (High Range) CHANNEL CALIBRATION may consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr and a one point calibration check of the detector below 10 R/hr with an installed or portable gamma source. The Frequency is based on operating experience and consistency with the typical industry refueling cycle. Whenever an RTD is replaced in Functions 2 or 3, the next required CHANNEL CALIBRATION of the RTD's is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. Whenever a core exit thermocouple is replaced in Functions 14, 15, 16, or 17, the next required CHANNEL CALIBRATION of the core exit thermocouples is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

REFERENCES

1. USAR Appendix 7A.
2. Regulatory Guide 1.97, Rev. 2, December 1980.
3. NUREG-0737, Supplement 1, "TMI Action Items."
4. USAR Figure 5.1-1 (sheet 4).
5. NA 94-0089 dated May 24, 1994.

BASES

REFERENCES (continued)

6. USAR Section 18.2.13.

7. NUREG-0881, Wolf Creek SER, Section 22, TMI Item 2.F.2 and SER Supplement 5.

8. USAR Section 18.2.8.1.

9. USAR Sections 10.4.9 and 18.2.8.

10. USAR Section 18.2.13.2.

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the plant in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the steam generator (SG) safety valves or the SG atmospheric relief valves (ARVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3.

If the control room becomes inaccessible, the operators can establish control at the auxiliary shutdown panel (ASP), and place and maintain the unit in MODE 3. Not all controls and necessary transfer switches are located at the auxiliary shutdown panel. Some controls and transfer switches will have to be operated locally at the switchgear, motor control panels, or other local stations. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the required remote shutdown control and instrumentation functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 3 should the control room become inaccessible:

	FUNCTION	TOTAL NO. OF CHANNELS	READOUT LOCATION
1.	Source Range, Neutron Flux	2	Auxiliary Shutdown Panel
2.	Reactor Trip Breaker Indication	1/RTB	Reactor Trip Switchgear
3.	Pressurizer Pressure	1	Auxiliary Shutdown Panel
4.	RCS Pressure - Wide Range	2	Auxiliary Shutdown Panel
5.	Reactor Coolant Temperature - Hot Leg	2	Auxiliary Shutdown Panel

BASES

BACKGROUND
(continued)

	FUNCTION	TOTAL NO. OF CHANNELS	READOUT LOCATION
6.	Reactor Coolant Temperature - Cold Leg	4	Auxiliary Shutdown Panel
7.	SG Pressure	2/SG	Auxiliary Shutdown Panel
8.	SG Level	2/SG	Auxiliary Shutdown Panel
9.	AFW Flow Rate	4	Auxiliary Shutdown Panel
10.	Reactor Coolant Pump Breakers	1/pump	13.8-kV Switchgear
11.	AFW Suction Pressure	3	Auxiliary Shutdown Panel
12.	Pressurizer Level	2	Auxiliary Shutdown Panel

AUXILIARY SHUTDOWN PANEL CONTROLS

1. START/STOP control for each motor-driven AFW pump
2. START/STOP control for the turbine-driven AFW pump (steam supply and throttle valve controls)
3. MANUAL control for all AFW flow control valves
4. OPEN/CLOSE control for ESW and CST to the AFW pump suction valves
5. AFW pump turbine speed control
6. AUTOMATIC/MANUAL control for each power-operated atmospheric relief valve
7. ON/OFF control for two pressurizer backup heater groups
8. OPEN/CLOSE control for the containment isolation valves in the letdown line
9. OPEN/CLOSE control for shutoff valves in the letdown line upstream of the regenerative heat exchanger and for the letdown orifice isolation valves

BASES

APPLICABLE SAFETY ANALYSES (continued)

locations are utilized, if needed, to ensure that the transport delay time of the leakage from its source to an instrument location yields an acceptable overall response time.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leak occur detrimental to the safety of the unit and the public.

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).

LCO

One method of protecting against large RCS leakage derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the Containment Sump Level and Flow Monitoring System, one containment atmosphere particulate radioactivity monitor and either the Containment Cooler Condensate Flow Monitoring System or one containment atmosphere gaseous radioactivity monitor provide an acceptable minimum.

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is required to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

The Actions are modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the Containment Sump Level and Flow Monitoring System is inoperable. This allowance is provided because other instrumentation is available to monitor RCS leakage.

BASES

ACTIONS

A.1 and A.2

A primary system leak would result in reactor coolant flowing into the containment normal sumps or into the instrument tunnel sump. Indication of increasing sump level is transmitted to the control room by means of individual sump level transmitters. This information is used to provide measurement of low leakage by monitoring level increase versus time.

With the required Containment Sump Level and Flow Monitoring System inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere particulate radioactivity monitor will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (near operating rated operating pressure with stable RCS pressure, temperature, power level, pressurizer and makeup tank level, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Restoration of the required Containment Sump Level and Flow Monitoring System to OPERABLE status within a Completion Time of 30 days is required to regain the function after the system's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

B.1.1, B.1.2, and B.2

With the containment atmosphere particulate radioactivity monitoring instrumentation channel inoperable, alternative action is required. Either samples of the containment atmosphere must be taken and analyzed for gaseous and particulate radioactivity or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere particulate radioactivity monitor.

BASES

ACTIONS

B.1.1, B.1.2, and B.2 (continued)

The 24 hour interval provides periodic information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (near operating rated operating pressure with stable RCS pressure, temperature, power level, pressurizer and makeup tank level, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

C.1.1, C.1.2, C.2.1, and C.2.2

With the required containment atmosphere gaseous radioactivity monitor and the required Containment Cooler Condensate Monitoring System inoperable, the means of detecting leakage are the Containment Sump Level and Flow Monitoring System and the containment atmosphere particulate radioactivity monitor. This Condition does not provide all the required diverse means of leakage detection. With the containment atmosphere radioactivity monitoring and Containment Cooler Condensate Monitoring System instrumentation channels inoperable, alternative action is required. Either samples of the containment atmosphere must be taken and analyzed for gaseous and particulate radioactivity or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (near operating rated operating pressure with stable RCS pressure, temperature, power level, pressurizer and makeup tank level, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The followup Required Action is to restore either of the inoperable required monitoring methods to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a reduced configuration for a lengthy time period.

Refer to LCO 3.3.6, “Containment Purge Isolation Instrumentation,” upon a loss of the required containment atmosphere radioactivity monitor to ensure LCO requirements are met.

BASES

ACTIONS (continued)

D.1 and D.2

If a Required Action of Condition A, B or C cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

With all required monitoring methods inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere particulate and gaseous radioactivity monitors. The check gives reasonable confidence that the channel are operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.15.2

SR 3.4.15.2 requires the performance of a COT on the required containment atmosphere particulate and gaseous radioactivity monitors. The test ensures that the monitors can perform their function in the desired manner. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation.

SR 3.4.15.3, SR 3.4.15.4, and SR 3.4.15.5

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 18 months is a

BASES

LCO (continued)

Leakage Rate Testing Program leakage test. At this time, the applicable leakage limits must be met.

Compliance with this LCO will ensure a containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

Individual leakage rates for the containment air lock (LCO 3.6.2) and containment purge valves with resilient seals (LCO 3.6.3) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J, Option B. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 L_a.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock and purge valve with resilient seal leakage limits specified in LCO 3.6.2 and LCO 3.6.3 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test is required to be < 0.6 L_a for combined Type B and C leakage, and ≤ 0.75 L_a for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

SR 3.6.1.2

This SR ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Tendon Surveillance Program. Testing and Frequency are consistent with the recommendations of Regulatory Guide 1.35 (Ref. 4).

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. USAR, Chapter 15.
3. USAR, Section 6.2.
4. Regulatory Guide 1.35, Draft Revision 3, April 1979.

BASES

ACTIONS (continued)

In the event the containment isolation valve leakage results in exceeding the overall containment leakage rate acceptance criteria, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable except for purge valve leakage not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve (this includes power operated valves with power removed), a blind flange, or a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. The isolation barrier utilized to satisfy Required Action A.1 must have been demonstrated to meet the leakage requirements of SR 3.6.1.1. Required Action A.1 must be completed within 4 hours. 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.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification, through a system walkdown (which may include the use of local or remote indicators), that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. 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.

Condition A has been modified by a Note indicating that this condition is only applicable to those penetration flow paths with two containment

BASES

ACTIONS

A.1 and A.2 (continued)

isolation valves. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate actions.

Required Action A.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 devices once they have been verified to be in the proper position, is small.

B.1

With two containment isolation valves in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve (this includes power operated valves with power removed), and a blind flange. For a penetration flow path isolated in accordance with Required Action B.1, the device used to isolate the penetration should be the closest available one to containment. The isolation barrier utilized to satisfy Required Action B.1 must have been demonstrated to meet the leakage requirements of SR 3.6.1.1. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration 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 penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two containment isolation valves. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate Required Actions.

BASES

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. For a penetration flow path isolated in accordance with Required Action C.1, the device used to isolate the penetration should be the closest available one to containment. The isolation barrier utilized to satisfy Required Action C.1 must have been demonstrated to meet the leakage requirements of SR 3.6.1.1. A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment OPERABILITY during MODES 1, 2, 3, and 4. The closed system must meet the requirement of Reference 5. The Containment Spray System and ECCS are closed ESF-grade systems outside containment, which meet the requirements of Reference 5, and serve as the second containment isolation barrier (Ref. 6). In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. This Note is necessary since this Condition is written specifically to address these penetration flow paths. For penetration flow paths with two containment isolation valves, Conditions A and B provide the appropriate Required Actions.

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges 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

BASES

ACTIONS

C.1 and C.2 (continued)

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.

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.

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

BASES

ACTIONS

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

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.

E.1 and E.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 36 inch containment shutdown purge supply and exhaust valve is required to be verified sealed closed or closed and blind flange installed at 31 day intervals. Each 36 inch containment shutdown purge supply and exhaust valve inside containment must be verified sealed closed or blind flange installed prior to entering MODE 4 from MODE 5, if the surveillance has not been performed in the previous 92 days. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment shutdown purge valve. Detailed analysis of these valves failed to conclusively demonstrate their ability to close during a LOCA in time to limit offsite doses. Therefore, these valves are required to be in the sealed closed position or closed and blind flange installed during MODES 1, 2, 3, and 4. A containment shutdown purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or by removing the air supply to the valve operator. In this application, the term "sealed" has no

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1 (continued)

connotation of leak tightness. The Frequency is a result of an NRC initiative, Multi-Plant Action No. B-24 (Ref. 4), related to containment purge valve use during plant operations. In the event valve leakage requires entry into Condition D, the Surveillance permits opening one purge valve in a penetration flow path to perform repairs.

SR 3.6.3.2

This SR ensures that the mini-purge valves are closed as required or, if open, open for an allowable reason. If a mini-purge valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the mini-purge valves are open for the reasons stated. The valves may be opened for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. The mini-purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other containment isolation valve requirements discussed in SR 3.6.3.3.

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. 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 those containment isolation valves outside containment and capable of being mispositioned are in the correct position. Since verification of valve position for containment isolation valves outside containment is relatively easy, the 31 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing or securing.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3 (continued)

The Note applies to valves and blind flanges 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 during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.4

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing or securing.

A Note has been added that allows valves and blind flanges located in high radiation areas 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 during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position is small.

SR 3.6.3.5

Verifying that the isolation time of each automatic power operated containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. Isolation times are provided in USAR Figure 6.2.4-1. The Frequency of this SR is in accordance with the Inservice Testing Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.6

Leakage integrity tests with a maximum allowable leakage rate for containment shutdown purge supply and exhaust isolation valves will provide early indication of resilient material seal degradation and will allow opportunity for repair before gross leakage failures could develop.

This SR is modified by a Note indicting that the SR is only required to be performed when the containment shutdown purge valves blind flanges are installed.

If the blind flange is installed, leakage rate testing of the valve and its associated blind flange must be performed every 24 months and following each reinstallation of the blind flange. Operating experience has demonstrated that this testing frequency is adequate to assure this penetration is leak tight.

The combined leakage rate for the containment shutdown purge supply and exhaust isolation valves, when pressurized to P_a, and included with all Type B and C penetrations is less than .60 L_a.

SR 3.6.3.7

For containment mini-purge and shutdown purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation and the importance of maintaining this penetration leak tight (due to the direct path between containment and the environment), a Frequency of 184 days was established as part of the NRC resolution of Multi-Plant Action No. B-20, "Containment Leakage Due to Seal Deterioration" (Ref. 3).

Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that occurring to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

The SR is modified by a Note indicating that the SR is only required to be performed for the containment shutdown purge valves when the associated blind flange is removed.

The measured leakage rate for each containment mini-purge supply and exhaust isolation valve with resilient seals is less than 0.05 L_a when pressurized to P_a. The combined leakage rate for the containment shutdown purge supply and exhaust isolation valves, when pressurized to P_a, and included with all Type B and C penetrations is less than .60 L_a.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.8

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation 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 this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 15.
2. USAR, Figure 6.2.4-1.
3. Multi-Plant Action MPA-B020, "Containment Leakage Due to Seal Deterioration."
4. Multi-Plant Action MPA-B024, "Venting and Purging Containment's While at Full Power and Effect of LOCA."
5. USAR, Section 6.2.4.
6. NUREG-0881, "Safety Evaluation Report related to the operation of Wolf Creek Generating Station, Unit No. 1," Section 6.2.3, April 1982.

B 3.7 PLANT SYSTEMS

B 3.7.17 Spent Fuel Assembly Storage

BASES

BACKGROUND

The high density rack modules for the fuel storage pool are designed for storage of both new fuel and spent fuel. Spent fuel storage is designated into Regions based upon initial enrichment and accumulated burnup. Region 1 locations are designed to accommodate new fuel with a nominal maximum enrichment of 4.6 wt% U-235 with no integral fuel burnable absorber (IFBA) or up to a nominal maximum enrichment of 5.0 wt% U-235 with 16 IFBA (Ref. 3); or spent fuel regardless of the discharge fuel burnup. Region 2 and Region 3 are designed to accommodate fuel of various initial enrichments which have accumulated minimum burnups within the acceptable domain according to Figure 3.7.17-1, in the accompanying LCO.

Prior to storage of spent fuel assemblies in the fuel storage pool, overall pool storage configurations are prepared in accordance with administrative controls. The pool layouts include sufficient Region 1 storage to accommodate new and discharged fuel assemblies with low burnup. Fuel storage utilizes either a Mixed Zone Three Region configuration and/or a checkerboarding configurations.

In a Mixed Zone Three Region configuration, Region 1 storage cells are only located along the outside periphery of the rack modules and must be separated by one or more Region 2 storage cells. Region 1 storage cells may be located directly across from one another since they are separated by a water gap. The outer rows of alternating Region 1 and 2 storage cells must be further separated from the internal Region 3 storage cells by one or more Region 2 storage cells.

In the checkerboarding configuration, fuel assemblies are placed in an alternating checkerboard-style pattern with empty storage cells (i.e., fuel assemblies are surrounded on all four sides by empty storage cells, except at the checkerboard boundary). Region 1 fuel assemblies may not be located directly across from one another, even when separated by a water gap. This arrangement may be used anywhere in the fuel storage area if the checkerboarding pattern is maintained in linear array equal to or greater than 2X2. A checkerboard area may be bounded by either a water gap, empty cells, Region 2 fuel assemblies or Region 3 fuel assemblies but shall not be developed within the same rack as a Mixed Zone Three Region configuration.

BASES

BACKGROUND (continued)

The water in the fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design of all three regions is based on the use of unborated water, which maintains the fuel storage pool in a subcritical condition during normal operation with the regions fully loaded. The double contingency principle discussed in ANSI N-16.1-1975 and the April 1978 NRC letter (Ref. 2) allows credit for soluble boron under other abnormal or accident conditions, since only a single accident need be considered at one time. For example, the most severe accident scenarios, for which boron credit is taken, are:

a. Inadvertent loading of 5.0 wt% U-235 new fuel assemblies in a Region 2 or Region 3 storage cell in a Mixed Zone Three Region configuration, or in a empty cell in a checkerboard configuration.

b. Mis-location of a new fuel assembly in the gap between the rack modules and the concrete wall in the fuel storage pool.

c. Inadvertent loading of 5.0 wt% U-235 new fuel assemblies with 16 IFBA into all storage cells in the fuel storage pool.

APPLICABLE SAFETY ANALYSES

The hypothetical accidents can only take place during or as a result of the movement of assemblies (Ref. 1). For these accident occurrences, the presence of soluble boron in the fuel storage pool maintains subcriticality with a K_{eff} of 0.95 or less.

The configuration of fuel assemblies in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The restrictions on the placement of fuel assemblies within the fuel storage pool, in accordance with Figure 3.7.17-1 or Specification 4.3.1.1 in Section 4.3, in the accompanying LCO, ensures the k_{eff} of the fuel storage pool will always remain < 0.95, assuming the pool to be flooded with unborated water. The fuel storage pool consists of the spent fuel pool and cask loading pool (with racks installed).

APPLICABILITY

This LCO applies whenever any fuel assembly is stored in Region 2 or 3 of the fuel storage pool.

BASES

APPLICABLE SAFETY ANALYSES (continued)

meeting the design basis of the unit. This results in maintaining at least one train of the onsite or offsite AC sources OPERABLE during Accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power System, separate and independent DGs for each train, and redundant LSELS for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

One offsite circuit consists of the #7 transformer feeding through the 13-48 breaker power the ESF transformer XNB01, which, in turn powers the NB01 bus through its normal feeder breaker. Transformer XNB01 may also be powered from the SL-7 supply through the 13-8 breaker provided the offsite 69 KV line is not connected to the 345 kV system. Another offsite circuit consists of the startup transformer feeding through breaker PA201 powering the ESF transformer XNB02, which, in turn powers the NB02 bus through its normal feeder breaker.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 12 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

Upon failure of the DG lube oil keep warm system, the DG remains OPERABLE until the applicable low temperature alarm condition is

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LCO (continued)

achieved. Upon failure of the DG jacket water keep warm system, the DG remains OPERABLE as long as jacket water temperature is ≥ 105 °F (Ref. 13).

Initiating an EDG start upon a detected undervoltage or degraded voltage condition, tripping of nonessential loads, and proper sequencing of loads, is a required function of LSELS and required for DG OPERABILITY. In addition, the LSELS Automatic Test Indicator (ATI) is an installed testing aid and is not required to be OPERABLE to support the sequencer function. Absence of a functioning ATI does not render LSELS inoperable.

The AC sources in one train must be separate and independent of the AC sources in the other train. For the DGs, separation and independence are complete.

For the offsite AC source, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus provided the appropriate LCO Required Actions are entered for loss of one offsite power source.

APPLICABILITY

The AC sources and LSELS are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if the second

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil temperature are being maintained consistent with manufacturer recommendations.

In order to reduce stress and wear on diesel engines, the manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3, which is only applicable when such modified start procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions using one of the following signals and achieves required voltage and frequency within 12 seconds:

a. Manual, or
b. Simulated loss of offsite power by itself, or
c. Safety Injection test signal.

The 12 second start requirement supports the assumptions of the design basis LOCA analysis in the USAR, Chapter 15 (Ref. 5).

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

The 12 second start requirement is not applicable to SR 3.8.1.2 (see Note 3) when a modified start procedure as described above is used. If a modified start is not used, the 12 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 12 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is the intent of Note 1 of SR 3.8.1.2.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads and aligned to provide standby power to the associated emergency buses. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients, because of changing bus loads, do not invalidate this test. Momentary power

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

factor transients transients outside the normal range are acceptable during this surveillance since no power factor requirements are established by this SR. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that, with the DG in a standby condition, the fuel oil transfer pump starts on low level in the day tank standpipe and shuts down on high level in the day tank standpipe to automatically maintain the day tank fuel oil level above the DG fuel headers. The fuel oil standpipe must have adequate level to keep the fuel oil supply header to the engine injector pumps full, so that the engine can meet the required 12 second start time. The minimum fuel oil free surface elevation is required to be at least 86 inches from the bottom (outside diameter) of the tank. The transfer pump start/stop setpoints are controlled to maintain level in the standpipe in order to ensure there is sufficient fuel to meet the 12 second start requirement for the DG. This level also ensures adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 10). This SR is for preventative

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.5 (continued)

maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The Frequency for this SR is 31 days.

Periodically, the capability of the fuel oil transfer pump to supply the opposite train DG via the installed cross-connect line is verified.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Not Used.

SR 3.8.1.9

Not Used.

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

The requirement to verify the connection of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems.

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

The 18 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from service.

SR 3.8.1.14

Regulatory Guide 1.9, Rev. 3, (Ref. 3), requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG (Refer to discussion of Note 3 below). The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor of ≥ 0.8 and ≤ 0.9 at a voltage of 4160 +160 -420 volts and a frequency of 60 ± 1.2 Hz. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients outside the power factor range will not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. Note 3 permits the elimination of the 2-hour overload test, provided that the combined emergency loads on a DG do not exceed its continuous duty rating.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 12 seconds. The 12 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3).

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.16

As required by Regulatory Guide 1.9, Rev. 3 (Ref. 3), this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and the DG can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready to load status when the DG is at rated speed and voltage, the output breaker is open and can receive a close signal on bus undervoltage, and the load sequence timers are reset.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3), and takes into consideration unit conditions required to perform the Surveillance.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.17

Demonstration of the test mode (parallel mode) override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready to load operation if a Safety Injection actuation signal is received during operation in the test mode. Ready to load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 13), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading was not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

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REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. USAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3.
4. USAR, Chapter 6.
5. USAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, Rev. 0, January 1978.
11. ASME, Boiler and Pressure Vessel Code, Section XI.
12. IEEE Standard 308-1978.
13. Configuration Change Package (CCP) 08052, Revision 1, April 23, 1999.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.7 (continued)

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified performance discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to trend overall battery degradation due to age and usage.

A battery modified performance discharge test is described in the Bases for SR 3.8.4.7. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

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SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

The manufacturer recommends that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. However, based on discussions with the NRC associated with the AT&T round cell batteries (Reference 13), the SR specifies a battery capacity of 85%. If battery capacity is below 85% of the manufacturer's rating, the battery is to be replaced. The battery capacity is determined using the manufacturer's minimum lifetime rating. Adverse trends in the battery capacity identified during the performance of this SR are evaluated in accordance with the corrective action program.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 18 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 9), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer's rating.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE-308-1978.
4. USAR, Chapter 8.
5. IEEE-485-1983, June 1983.
6. USAR, Chapter 6.
7. USAR, Chapter 15.
8. Regulatory Guide 1.93, December 1974.

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B 3.1.1-4	0	Amend. No. 123	12/18/99
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
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B 3.1.8-3	0	Amend. No. 123	12/18/99
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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	0	Amend. No. 123	12/18/99
B 3.2.1-7	0	Amend. No. 123	12/18/99
B 3.2.1-8	0	Amend. No. 123	12/18/99
B 3.2.1-9	4	DRR 00-1365	9/28/00
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	0	Amend. No. 123	12/18/99
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B 3.3.1-27	0	Amend. No. 123	12/18/99
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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	8	DRR 01-1235	9/19/01
B 3.3.3-11	8	DRR 01-1235	9/19/01
B 3.3.3-12	8	DRR 01-1235	9/19/01
B 3.3.3-13	8	DRR 01-1235	9/19/01
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	6	DRR 00-1541	3/13/01
B 3.3.4-3	1	DRR 99-1624	12/18/99
B 3.3.4-4	1	DRR 99-1624	12/18/99
B 3.3.4-5	1	DRR 99-1624	12/18/99
B 3.3.4-6	0	Amend. No. 123	12/18/99
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
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	0	Amend. No. 123	12/18/99
B 3.3.5-7	0	Amend. No. 123	12/18/99
B 3.3.6-1	0	Amend. No. 123	12/18/99
B 3.3.6-2	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 3.3.6-3	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	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
B 3.4.1-3	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
B 3.4.5-3	0	Amend. No. 123	12/18/99
B 3.4.5-4	0	Amend. No. 123	12/18/99
B 3.4.5-5	0	Amend. No. 123	12/18/99
B 3.4.5-6	0	Amend. No. 123	12/18/99
B 3.4.6-1	0	Amend. No. 123	12/18/99
B 3.4.6-2	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 3.4.6-3	0	Amend. No. 123	12/18/99
B 3.4.6-4	0	Amend. No. 123	12/18/99
B 3.4.6-5	0	Amend. No. 123	12/18/99
B 3.4.7-1	0	Amend. No. 123	12/18/99
B 3.4.7-2	1	DRR 99-1624	12/18/99
B 3.4.7-3	0	Amend. No. 123	12/18/99
B 3.4.7-4	0	Amend. No. 123	12/18/99
B 3.4.7-5	1	DRR 99-1624	12/18/99
B 3.4.8-1	0	Amend. No. 123	12/18/99
B 3.4.8-2	0	Amend. No. 123	12/18/99
B 3.4.8-3	0	Amend. No. 123	12/18/99
B 3.4.8-4	0	Amend. No. 123	12/18/99
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	5	DRR 00-1427	10/12/00
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	1	DRR 99-1624	12/18/99
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	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
B 3.4.12-13	0	Amend. No. 123	12/18/99
B 3.4.12-14	0	Amend. No. 123	12/18/99
B 3.4.13-1	0	Amend. No. 123	12/18/99
B 3.4.13-2	0	Amend. No. 123	12/18/99
B 3.4.13-3	0	Amend. No. 123	12/18/99
B 3.4.13-4	0	Amend. No. 123	12/18/99
B 3.4.13-5	0	Amend. No. 123	12/18/99
B 3.4.13-6	0	Amend. No. 123	12/18/99
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

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TAB – B 3.4 REACTOR COOLANT SYSTEM (RCS) (continued)			
B 3.4.14-5	0	Amend. No. 123	12/18/99
B 3.4.14-6	0	Amend. No. 123	12/18/99
B 3.4.15-1	2	DRR 00-0147	4/24/00
B 3.4.15-2	0	Amend. No. 123	12/18/00
B 3.4.15-3	2	DRR 00-0147	4/24/00
B 3.4.15-4	7	DRR 01-0474	5/1/01
B 3.4.15-5	7	DRR 01-0474	5/1/01
B 3.4.15-6	0	Amend. No. 123	12/18/99
B 3.4.15-7	0	Amend. No. 123	12/18/99
B 3.4.16-1	0	Amend. No. 123	12/18/99
B 3.4.16-2	1	DRR 99-1624	12/18/99
B 3.4.16-3	0	Amend. No. 123	12/18/99
B 3.4.16-4	0	Amend. No. 123	12/18/99
B 3.4.16-5	0	Amend. No. 123	12/18/99
B 3.4.16-6	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
B 3.5.2-6	0	Amend. No. 123	12/18/99
B 3.5.2-7	0	Amend. No. 123	12/18/99
B 3.5.2-8	0	Amend. No. 123	12/18/99
B 3.5.2-9	0	Amend. No. 123	12/18/99
B 3.5.2-10	0	Amend. No. 123	12/18/99
B 3.5.3-1	0	Amend. No. 123	12/18/99
B 3.5.3-2	0	Amend. No. 123	12/18/99
B 3.5.3-3	0	Amend. No. 123	12/18/99
B 3.5.3-4	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
B 3.5.5-1	2	Amend. No. 132	4/24/00
B 3.5.5-2	2	Amend. No. 132	4/24/00
B 3.5.5-3	2	Amend. No. 132	4/24/00
B 3.5.5-4	2	Amend. No. 132	4/24/00

PAGE (1)	REVISION NO. (2)	CHANGE DOCUMENT (3)	DATE EFFECTIVE/ IMPLEMENTED (4)
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	0	Amend. No. 123	12/18/99
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	8	DRR 01-1235	9/19/01
B 3.6.3-6	8	DRR 01-1235	9/19/01
B 3.6.3-7	8	DRR 01-1235	9/19/01
B 3.6.3-8	8	DRR 01-1235	9/19/01
B 3.6.3-9	8	DRR 01-1235	9/19/01
B 3.6.3-10	8	DRR 01-1235	9/19/01
B 3.6.3-11	8	DRR 01-1235	9/19/01
B 3.6.3-12	8	DRR 01-1235	9/19/01
B 3.6.3-13	8	DRR 01-1235	9/19/01
B 3.6.4-1	2	DRR 00-0147	4/24/00
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	0	Amend. No. 123	12/18/99
B 3.6.5-3	0	Amend. No. 123	12/18/99
B 3.6.5-4	0	Amend. No. 123	12/18/99
B 3.6.6-1	0	Amend. No. 123	12/18/99
B 3.6.6-2	0	Amend. No. 123	12/18/99
B 3.6.6-3	1	DRR 99-1624	12/18/99
B 3.6.6-4	0	Amend. No. 123	12/18/99
B 3.6.6-5	0	Amend. No. 123	12/18/99
B 3.6.6-6	0	Amend. No. 123	12/18/99
B 3.6.6-7	0	Amend. No. 123	12/18/99
B 3.6.6-8	0	Amend. No. 123	12/18/99
B 3.6.6-9	0	Amend. No. 123	12/18/99
B 3.6.7-1	0	Amend. No. 123	12/18/99
B 3.6.7-2	0	Amend. No. 123	12/18/99
B 3.6.7-3	0	Amend. No. 123	12/18/99
B 3.6.7-4	2	DRR 00-0147	4/24/00
B 3.6.7-5	0	Amend. No. 123	12/18/99
B 3.6.8-1	0	Amend. No. 123	12/18/99
B 3.6.8-2	0	Amend. No. 123	12/18/99
B 3.6.8-3	0	Amend. No. 123	12/18/99
B 3.6.8-4	0	Amend. No. 123	12/18/99
B 3.6.8-5	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			
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	0	Amend. No. 123	12/18/99
B 3.7.1-6	0	Amend. No. 123	12/18/99
B 3.7.2-1	0	Amend. No. 123	12/18/99
B 3.7.2-2	0	Amend. No. 123	12/18/99
B 3.7.2-3	0	Amend. No. 123	12/18/99
B 3.7.2-4	0	Amend. No. 123	12/18/99
B 3.7.2-5	0	Amend. No. 123	12/18/99
B 3.7.2-6	0	Amend. No. 123	12/18/99
B 3.7.3-1	0	Amend. No. 123	12/18/99
B 3.7.3-2	0	Amend. No. 123	12/18/99
B 3.7.3-3	0	Amend. No. 123	12/18/99
B 3.7.3-4	0	Amend. No. 123	12/18/99
B 3.7.3-5	0	Amend. No. 123	12/18/99
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	1	DRR 99-1624	12/18/99
B 3.7.4-4	1	DRR 99-1624	12/18/99
B 3.7.4-5	1	DRR 99-1624	12/18/99
B 3.7.5-1	0	Amend. No. 123	12/18/99
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	1	DRR 99-1624	12/18/99
B 3.7.5-5	0	Amend. No. 123	12/18/99
B 3.7.5-6	0	Amend. No. 123	12/18/99
B 3.7.5-7	0	Amend. No. 123	12/18/99
B 3.7.5-8	0	Amend. No. 123	12/18/99
B 3.7.5-9	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
B 3.7.10-2	0	Amend. No. 123	12/18/99
B 3.7.10-3	0	Amend. No. 123	12/18/99
B 3.7.10-4	0	Amend. No. 123	12/18/99

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TAB – B 3.7 PLANT SYSTEMS (continued)			
B 3.7.10-5	0	Amend. No. 123	12/18/99
B 3.7.10-6	0	Amend. No. 123	12/18/99
B 3.7.10-7	0	Amend. No. 123	12/18/99
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	1	DRR 99-1624	12/18/99
B 3.7.13-2	1	DRR 99-1624	12/18/99
B 3.7.13-3	1	DRR 99-1624	12/18/99
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	1	DRR 99-1624	12/18/99
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
B 3.7.16-2	1	DRR 99-1624	12/18/99
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
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	6	DRR 00-1541	3/13/01
B 3.8.1-4	6	DRR 00-1541	3/13/01
B 3.8.1-5	0	Amend. No. 123	12/18/99
B 3.8.1-6	0	Amend. No. 123	12/18/99
B 3.8.1-7	0	Amend. No. 123	12/18/99
B 3.8.1-8	0	Amend. No. 123	12/18/99
B 3.8.1-9	0	Amend. No. 123	12/18/99
B 3.8.1-10	0	Amend. No. 123	12/18/99
B 3.8.1-11	0	Amend. No. 123	12/18/99
B 3.8.1-12	0	Amend. No. 123	12/18/99
B 3.8.1-13	0	Amend. No. 123	12/18/99
B 3.8.1-14	0	Amend. No. 123	12/18/99
B 3.8.1-15	0	Amend. No. 123	12/18/99
B 3.8.1-16	7	DRR 01-0474	5/1/01
B 3.8.1-17	7	DRR 01-0474	5/1/01
B 3.8.1-18	0	Amend. No. 123	12/18/99
B 3.8.1-19	0	Amend. No. 123	12/18/99
B 3.8.1-20	0	Amend. No. 123	12/18/99

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TAB – B 3.8 ELECTRICAL POWER SYSTEMS (continued)			
B 3.8.1-21	8	DRR 01-1235	9/19/01
B 3.8.1-22	0	Amend. No. 123	12/18/99
B 3.8.1-23	7	DRR 01-0474	5/1/01
B 3.8.1-24	0	Amend. No. 123	12/18/99
B 3.8.1-25	0	Amend. No. 123	12/18/99
B 3.8.1-26	0	Amend. No. 123	12/18/99
B 3.8.1-27	6	DRR 00-1541	3/13/01
B 3.8.2-1	0	Amend. No. 123	12/18/99
B 3.8.2-2	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
B 3.8.2-6	0	Amend. No. 123	12/18/99
B 3.8.2-7	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
B 3.8.5-5	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99

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TAB – B 3.8 ELECTRICAL POWER SYSTEMS (continued)			
B 3.8.8-5	0	Amend. No. 123	12/18/99
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
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	0	Amend. No. 123	12/18/99
TAB – B 3.9 REFUELING OPERATIONS			
B 3.9.1-1	0	Amend. No. 123	12/18/99
B 3.9.1-2	0	Amend. No. 123	12/18/99
B 3.9.1-3	0	Amend. No. 123	12/18/99
B 3.9.1-4	0	Amend. No. 123	12/18/99
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	0	Amend. No. 123	12/18/99
B 3.9.3-2	0	Amend. No. 123	12/18/99
B 3.9.3-3	0	Amend. No. 123	12/18/99
B 3.9.4-1	4	DRR 00-1365	9/28/00
B 3.9.4-2	4	DRR 00-1365	9/28/00
B 3.9.4-3	4	DRR 00-1365	9/28/00
B 3.9.4-4	4	DRR 00-1365	9/28/00
B 3.9.4-5	4	DRR 00-1365	9/28/00
B 3.9.4-6	0	Amend. No. 123	12/18/99
B 3.9.5-1	0	Amend. No. 123	12/18/99
B 3.9.5-2	0	Amend. No. 123	12/18/99
B 3.9.5-3	0	Amend. No. 123	12/18/99
B 3.9.5-4	0	Amend. No. 123	12/18/99
B 3.9.6-1	0	Amend. No. 123	12/18/99
B 3.9.6-2	0	Amend. No. 123	12/18/99
B 3.9.6-3	0	Amend. No. 123	12/18/99
B 3.9.6-4	0	Amend. No. 123	12/18/99
B 3.9.7-1	0	Amend. No. 123	12/18/99
B 3.9.7-2	0	Amend. No. 123	12/18/99
B 3.9.7-3	0	Amend. No. 123	12/18/99

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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.