WOLF CREEK
NUCLEAR OPERATING CORPORATION

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CO 00-0007

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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Subject: Docket No. 50-482: Wolf Creek Generating Station Changes to Technical Specification Bases

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). Pursuant to TS Section 5.5.14, enclosed are those changes made to the WCGS TS Bases under the provisions of TS Section 5.5.14. This submittal reflects changes since the issuance of License Amendment No. 123 on March 31, 1999, through December 1999. The Attachment provides a list of commitments contained in this correspondence

If you have any questions concerning this report, please contact me at (316) 364-4048, or Mr. Michael J. Angus at (316) 364-4077.

Very truly yours,

Michael J. Angus FOR

Clay C. Warren

CCW/rlr

Enclosure
Attachment

cc: J. N. Donohew (NRC), w/e, w/a
W. D. Johnson (NRC), w/e, w/a
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A001

Enclosure to CO 00-0007

Wolf Creek Generating Station

Changes to Technical Specification Bases

BASES

ACTIONS (continued)

A.2

A reduction of the Power Range Neutron Flux- High trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Power Range Neutron Flux - High trip setpoints initially determined by Required Action A.2 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Power Range Neutron Flux - High trip setpoint reductions within 72 hours of $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Power Range Neutron Flux - High trip setpoints.

A.3

Reduction in the Overpower ΔT trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1. The maximum allowable Overpower ΔT trip setpoints initially determined by Required Action A.3 may be affected by subsequent determinations of $F_Q^C(Z)$ and would require Overpower ΔT trip setpoint reductions within 72 hours of the $F_Q^C(Z)$ determination, if necessary to comply with the decreased maximum allowable Overpower ΔT trip setpoints. Decreases in $F_Q^C(Z)$ would allow increasing the maximum Overpower ΔT trip setpoints.

A.4

Verification that $F_Q^C(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions. Inherent in this action is identification of the cause of the out of limit condition and the correction of the cause to the extent necessary to allow safe operation at the higher power level.

BASES

ACTIONS

B.1

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational transient occurs. Tightening both the positive and negative AFD limits by $\geq$ 1% for each 1% by which $F_Q^W(Z)$ exceeds its limit within the allowed Completion Time of 4 hours, restricts the axial flux distribution such that even if a transient occurred, core peaking factors are not exceeded.

Calculate the percent $F_Q^W(Z)$ exceeds its limit by the following expression:

$$\left\{\left(\frac{\text{maximum}}{\text{over } Z}\left[\frac{F_Q^C(Z) \text{ X } W(Z)}{\frac{CFQ}{P} \text{ X } K(Z)}\right]\right) - 1\right\} \text{ X } 100 \quad \text{for } P \geq 0.5$$

$$\left\{\left(\frac{\text{maximum}}{\text{over } Z}\left[\frac{F_Q^C(Z) \text{ X } W(Z)}{\frac{CFQ}{0.5} \text{ X } K(Z)}\right]\right) - 1\right\} \text{ X } 100 \quad \text{for } P < 0.5$$

C.1

If Required Actions A.1 through A.4 or B.1 are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 and SR 3.2.1.2 are modified by a Note. The Note applies during power ascensions following a plant shutdown (leaving Mode 1). The Note allows for power ascensions if the surveillances are not current. It states that THERMAL POWER may be increased until an equilibrium power level (i.e., equilibrium conditions) has been achieved at which a

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Power Range Neutron Flux, P-9 (continued)

The LCO requires four channels of Power Range Neutron Flux, P-9 interlock to be OPERABLE in MODE 1. The Trip Setpoint is ≤ 50% RTP.

In MODE 1, a turbine trip could cause a load rejection beyond the capacities of the Steam Dump and Reactor Control Systems, so the Power Range Neutron Flux interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at a power level sufficient to have a load rejection beyond the capacities of the Steam Dump and Reactor Control Systems.

e. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated at 10% power, as determined by two-out-of-four NIS power range channels. If power level falls below 10% RTP on 3 of 4 channels, Power Range Neutron Flux - Low reactor trip and the Intermediate Range Neutron Flux reactor trip and rod stop will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip. Note that blocking the reactor trip also blocks the signal to prevent automatic and manual rod withdrawal;

- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux - Low reactor trip;

- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip, and also to de-energize the NIS source range detectors;

- the P-10 interlock provides one of the two inputs to the P-7 interlock; and

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Power Range Neutron Flux, P-10 (continued)

- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux - Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2. The Trip Setpoint is 10% RTP

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux - Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

f. Turbine Impulse Pressure, P-13

The Turbine Impulse Pressure, P-13 interlock is actuated when the pressure in the first stage of the high pressure turbine is approximately 10% of the full power pressure. The full power pressure corresponds to the first stage pressure at 100% RTP. The interlock is determined by one-out-of-two pressure channels. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

The LCO requires two channels of Turbine Impulse Pressure, P-13 interlock to be OPERABLE in MODE 1. The Trip Setpoint is $\leq$ 10% Turbine Power.

The Turbine Impulse Chamber Pressure, P-13 interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

19. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RTS logic train that are racked in, closed, and capable of supplying power to the Rod Control System. Thus, the train may consist of the main breaker or main breaker and opposite train bypass breaker. If a bypass breaker is closed and supplying power to the Rod Control System, that specific trip breaker train is considered inoperable. Two OPERABLE trains ensure no single random failure can disable the RTS trip capability.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the Rod Control System, or declared inoperable under Function 19 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

21. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 19 and 20) and Automatic Trip Logic (Function 21) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

21. Automatic Trip Logic (continued)

breaker while the unit is at power. The reactor trip signals generated by the RTS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RTS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel will not prevent reactor trip.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

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

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.1-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Function channels provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function channels affected. When the Required Channels in Table 3.3-1 are specified on a per loop, per SG, per bus, etc., basis, then the Condition may be entered separately for each loop, SG, bus, etc., as appropriate.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RTS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.16 (continued)

surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.3.1.16 is modified by a Note stating that neutron detectors are excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input to the first electronic component in the channel.

REFERENCES

1. USAR, Chapter 7.
2. USAR, Chapter 15.
3. IEEE-279-1971.
4. 10 CFR 50.49.
5. WCNOC Nuclear Safety Analysis Setpoint Methodology for the Reactor Protection System, (TR-89-0001).
6. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
7. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.
8. WCAP-9226, "Reactor Core Response to Excessive Secondary Steam Releases," Revision, January 1978.
9. IE Information Notice 79-22, "Qualification of Control Systems," September 14, 1979.
10. "Wolf Creek Setpoint Methodology Report," SNP(KG)-492, August 29, 1984.

TABLE B 3.3.1-1
(Page 1 of 2)

FUNCTION	TRIP SETPOINT[(a)]
1. Manual Reactor Trip	NA
2. Power Range Neutron Flux	
a. High	≤ 109% of RTP
b. Low	≤ 25% of RTP
3. Power Range Neutron Flux	
a. High Positive Rate	≤ 4% of RTP with a time constant ≥ 2 seconds
b. High Negative Rate	≤ 4% of RTP with a time constant ≥ 2 seconds
4. Intermediate Range Neutron Flux	≤ 25% of RTP
5. Source Range Neutron Flux	≤ 10^5 cps
6. Overtemperature ΔT	See Table 3.3.1-1 Note 1
7. Overpower ΔT	See Table 3.3.1-1 Note 2
8. Pressurizer Pressure	
a. Low	≥ 1940 psig
b. High	≤ 2385 psig
9. Pressurizer Water level - High	≤ 92% of instrument span
10. Reactor Coolant Flow - Low	≥ 89.9% of loop design flow (90,324 gpm)
11. Not Used	
12. Undervoltage RCPs	≥ 10587 Vac
13. Underfrequency RCPs	≥ 57.2 Hz
14. Steam Generator (SG) Water Level Low - Low	≥ 23.5% of narrow range instrument span
15. Not Used	
16. Turbine Trip	
a. Low Fluid Oil Pressure	≥ 590.00 psig
b. Turbine Stop Valve Closure	≥ 1% open

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.11

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

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

SR 3.3.2.12

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

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

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

SR 3.3.2.13

SR 3.3.2.13 is the performance of a SLAVE RELAY TEST as described in SR 3.3.2.6, except that SR 3.3.2.13 has a Note specifying that it applies only to slave relays K602, K622, K624, K630, K740, and K741. These slave relays are tested with a Frequency of 18 months and prior to entering MODE 4 for Functions 1.b, 3.a.(2), and 7.a whenever the unit has been in MODE 5 or 6 for > 24 hours, if not performed within the previous 92 days (Reference 9). The 18 month Frequency for these slave relays is based on the need to perform this Surveillance under the conditions that apply during a unit outage to avoid the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.14

SR 3.3.2.6, except that SR 3.3.2.14 has a Note specifying that it applies only to slave relay K620. The SLAVE RELAY TEST of relay K620 does not include the circuitry associated with the main feedwater pump trip solenoids since that circuitry serves no required safety function. This slave relay is tested with a Frequency of 18 months and prior to entering MODE 2 for Function 5.a whenever the unit has been in MODE 5 or 6 for > 24 hours, if not performed within the previous 92 days (Reference 9). The 18 month Frequency for this slave relay is based on the need to perform this Surveillance under the conditions that apply during a unit outage to avoid the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 7.
3. USAR, Chapter 15.
4. IEEE-279-1971.
5. 10 CFR 50.49.
6. WCNOC Nuclear Safety Analysis Setpoint Methodology for the Reactor Protection System, TR-89-0001.
7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
8. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.
9. SLNRC 84-0038 dated February 27, 1984.
10. "Wolf Creek Setpoint Methodology Report," SNP (KG)-492, August 29, 1984.
11. Amendment No. 43 to Facility Operating License No. NPF-42, March 29, 1991.

TABLE B 3.3.2-1
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FUNCTION	TRIP SETPOINT[a]
1. Safety Injection	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Containment Pressure – High-1	$\leq$ 3.5 psig
d. Pressurizer Pressure - Low	$\geq$ 1830 psig
e. Steam Line Pressure - Low	$\geq$ 615 psig
2. Containment Spray	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Containment Pressure - High-3	$\leq$ 27.0 psig
3. Containment Isolation	
a. Phase A Isolation	
(1) Manual Initiation	N.A.
(2) Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
(3) Safety Injection	See Function 1 (Safety Injection)
b. Phase B Isolation	
(1) Manual Initiation	N.A.
(2) Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
(3) Containment Pressure - High-3	$\leq$ 27.0 psig
4. Steam Line Isolation	
a. Manual Initiation	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
c. Containment Pressure - High-2	$\leq$ 17.0 psig
d. Steam Line Pressure	
(1) Low	$\geq$ 615 psig
(2) Negative Rate - High	$\leq$ 100 psi

TABLE B 3.3.2-1
(Page 2 of 2)

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

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

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 Water Level Indicating System provides a direct measurement of the collapsed liquid level above the fuel alignment plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory.

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.

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.

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 conRtols
3. MANUAL control for all AFW flow control valves
4. OPEN/CLOSE control for ESW to the AFW pump suction
5. AFW pump turbine speed control
6. AUTOMATIC/MANUAL control for each power-operated atmospheric relief valve
7. ON/OFF/AUTO 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

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to promptly shut down and maintain the unit in a safe condition in MODE 3.

The criteria governing the design and specific system requirements of the Remote Shutdown System are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1).

The Remote Shutdown System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The Remote Shutdown System LCO provides the OPERABILITY requirements of the functions and ASP controls necessary to place and maintain the unit in MODE 3 from a location other than the control room. The functions required are listed in Table 3.3.4-1 in the accompanying LCO.

The required ASP controls are listed above and described in USAR Section 7.4.3.1.1. The remote shutdown panel controls not located at the ASP are described in USAR Section 7.4.3.1.2 and are excluded from the requirements of this LCO.

The controls, instrumentation, and transfer switches are required for:

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the SGs; and
- RCS inventory control.

A Function of a Remote Shutdown System is OPERABLE if the required number of channels needed to support the Remote Shutdown System Function identified in Table 3.3.4-1 are OPERABLE.

The remote shutdown instruments and required ASP controls covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the instruments and controls will be OPERABLE if unit conditions require that the Remote Shutdown System be placed in operation.

BASES

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore the remote shutdown instruments and required ASP controls if control room instruments or controls become unavailable.

ACTIONS

Note 1 is included which excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a unit shutdown. This exception is acceptable due to the low probability of an event requiring the Remote Shutdown System and because the equipment can generally be repaired during operation without significant risk of spurious trip.

Note 2 has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function listed on Table 3.3.4-1 and for each required ASP control. The Completion Time(s) of the inoperable channel(s)/train(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 3.3.4-1 are specified on a per trip breaker, per SG, or per pump basis, the Condition may be entered separately for each trip breaker, SG, or pump, as appropriate.

A.1

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System in Table 3.3.4-1, or one or more required ASP controls are inoperable.

The Required Action is to restore the required Function and ASP control to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

BASES

ACTIONS (continued)

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to 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.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

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

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If the channels are within the criteria, it is an indication that the channels are OPERABLE. 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.

For the RTB Position Function, this Surveillance Requirement is met by verifying the actual position at the RTB Switchgear to the RTB indication. For the RCP Breakers Function, this Surveillance Requirement is met by verifying the local breaker indication to the control room remote breaker indication.

As specified in the Surveillance, a CHANNEL CHECK is only required for those channels which are normally energized. Source Range Neutron Flux is de-energized in MODE 1 and in MODE 2 above the P-6 setpoint.

The Frequency of 31 days is based upon operating experience which demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1 (continued)

normal operational use of the displays associated with the LCO required channels.

SR 3.3.4.2

SR 3.3.4.2 verifies each required Remote Shutdown System ASP control circuit and transfer switch performs the intended function. This verification is performed from the auxiliary shutdown panel. Operation of the equipment from the auxiliary shutdown panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the unit can be placed and maintained in MODE 3 from the auxiliary shutdown panel and the local stations. 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. (However, this Surveillance is not required to be performed only during a unit outage.) Operating experience demonstrates that remote shutdown control channels usually pass the Surveillance test when performed at the 18 month Frequency.

SR 3.3.4.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency of 18 months is based upon operating experience and consistency with the typical industry refueling cycle.

Notes 1 and 2 have been added to exclude the Neutron detectors (Note 1), the reactor trip breakers and RCP breakers (Note 2) from CHANNEL CALIBRATION.

Whenever an RTD is replaced in Function 5 or 6, the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing elements.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.

B 3.3 INSTRUMENTATION

B 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. There are two sets of undervoltage/degraded voltage protection circuits, one for each 4.16 kV NB system bus. Each set consists of a loss of voltage and degraded voltage Function. The undervoltage/degraded voltage protection circuits are described in USAR Section 8.3.1.1.3 (Ref. 1).

Upon recognition of a loss of voltage at the 4.16 kV ESF buses, a logic signal generated by load shedder and emergency load sequencer (LSELS) initiates the following:

a) Trip the 4.16 kV preferred normal and alternate bus feeder breakers to remove the deficient power source to protect Class 1E equipment from damage;

b) Shed all loads from the bus except the Class 1E 480 Vac load centers and centrifugal charging pumps to prepare the buses for re-energization by the LSELS; and

c) Generate an LOP DG start signal.

Upon detection of a degraded voltage condition, LSELS initiates a logic signal which serves only to trip the 4.16 kV ESF bus normal and alternate feeder breakers. The undervoltage relays detect an undervoltage condition and the same initiation signals as described above are actuated.

Four instantaneous undervoltage relays with an associated time delay are provided for each 4.16 kV Class 1E NB system bus for detecting a loss of bus voltage. The outputs are combined in a two-out-of-four logic to generate an LOP signal if the voltage is below approximately 70% for 1 second (nominal delay). The time delay prevents undesirable trips arising from transient undervoltage conditions.

Four potential transformers provide input to four degraded voltage bistables with associated time delays for each 4.16 kV Class 1E system bus for detecting a sustained degraded voltage condition. Once the bistable has actuated, a timer in the LSELS circuitry provides an 8 second time delay to avoid false actuation on large motor starts other than an

BASES

BACKGROUND (continued)

RCP. There are four of these 8-second timers per bus, one for each degraded voltage channel. The bistable outputs are then combined in a two-out-of-four logic to generate a degraded voltage signal if the voltage is below approximately 90%. Once the two-out-of four logic is satisfied, contacts in the bus feeder breaker trip circuits closed to arm the tripping circuitry. If a safety injection signal (SIS) were to occur concurrently with or after the arming of the tripping circuitry, the bus feeder breaker would open immediately, a bus undervoltage would be sensed, and a LOP signal would be generated. Should the degraded voltage condition occur in a non-accident condition (no SIS present), an additional 111 second time delay is provided. These time delays are specific to the feeder breakers (2 per bus). If the degraded voltage is not alleviated in the overall 119 seconds (nominal delay), the bus feeder breaker is tripped.

OPERABILITY of LSELS is addressed in LCO 3.8.1, "AC Sources - Operating," And LCO 3.8.2, "AC Sources - Shutdown."

Trip Setpoints and Allowable Values

The Trip Setpoints used in the relays are based on References 1 and 2. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account.

The actual nominal Trip Setpoint entered into the relays is normally still more conservative than that required by the Allowable Value. The Trip Setpoints are the nominal value at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the two-sided tolerance band for channel accuracy. If the measured setpoint does not exceed the Allowable Value, the relay is considered OPERABLE.

Setpoints adjusted in accordance with the Allowable Value ensure that the consequences of accidents will be acceptable, provided the unit is operated from within the LCOs at the onset of the accident and that the equipment functions as designed.

Allowable Values and/or nominal Trip Setpoints are specified for each Function in SR 3.3.5.3. Nominal Trip Setpoints are also specified in the unit specific setpoint calculations. The nominal setpoints are selected to ensure that the setpoint measured by the surveillance procedure does not exceed the Allowable Value if the relay is performing as required. If the

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

measured setpoint does not exceed the Allowable Value, the relay is considered OPERABLE. Operation with a Trip Setpoint less conservative than the nominal Trip Setpoint, but within the Allowable Value, is acceptable provided that operation and testing is consistent with the assumptions of the setpoint calculation. Each Allowable Value and/or Trip Setpoint specified is more conservative than the analytical limit assumed in the transient and accident analyses in order to account for instrument uncertainties appropriate to the trip function.

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power. The analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 2, in which a loss of offsite power is assumed.

The delay times assumed in the safety analysis for the ESF equipment include the 12 second DG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in Bases Table B 3.3.2-2 include the appropriate DG loading and sequencing delay.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO for LOP DG start instrumentation requires that four channels per 4.16 kV NB system bus of both the loss of voltage and degraded voltage Functions shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, the four channels must be OPERABLE

BASES

LCO (continued)

whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed. Loss of the LOP DG Start Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. During the loss of offsite power the DG powers the motor driven auxiliary feedwater pumps which are automatically started after expiration of the appropriate time delays by the load shedder and emergency load sequencer. Failure of these pumps to start would leave the turbine driven pump, started by the BOP ESFAS directly upon receipt of a loss of voltage signal from the load shedder emergency and load sequencer output relays as well as an increased potential for a loss of decay heat removal through the secondary system. OPERABILITY of the load shedder and emergency load sequencer is addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the vital bus.

ACTIONS

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

A Note 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 in the LCO. 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.

<u>A.1</u>

Condition A applies to the LOP DG start Function with one loss of voltage or one degraded voltage channel per bus inoperable.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops - MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat either to the steam generator (SG) secondary side coolant via natural circulation (Ref. 3) or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification, but is not sufficient for the boron dilution analysis discussed below.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side wide range water levels above 66% to provide an alternate method for decay heat removal via natural circulation (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event.

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

RCS Loops - MODE 5 (Loops Filled) satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side wide range water level ≥ 66%. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side wide range water levels ≥ 66%. Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are required to be performed without flow or pump noise. The 1 hour time period is adequate to perform the necessary testing, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side wide range water levels are ≥ 66% ensures an alternate decay heat removal method is available via natural circulation in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side wide range water level is ≥ 66% in at least two SGs, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. USAR, Section 15.4.6.
2. NRC letter (W. Reckley to N. Carns) dated November 22, 1993: "Wolf Creek Generating Station - Positive Reactivity Addition; Technical Specification Bases Change."
3. NRC Information Notice 95-35, "Degraded Ability of SGs to Remove Decay Heat by Natural Circulation."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are safety-related DC solenoid operated valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished automatically below 2185 psig or manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

The power supplies to the PORVs and their block valves are Class 1E. The manual controls and LTOP portion of the actuation circuitry are also Class 1E. The pressure relief signal derived from the pressurizer pressure control system is non-1E and must be isolated as shown in Reference 1. The two PORVs and their associated block valves are powered from two separate safety trains (Ref. 2).

The plant has two PORVs, each having a relief capacity of 210,000 lb/hr at 2335 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer Pressure - High reactor trip setpoint following a step reduction of 50% of full load with steam dump. In addition, the PORVs minimize challenges to the pressurizer safety valves and also may be used for low temperature protection (LTOP). See LCO 3.4.12, "Low Temperature Protection(LTOP) System."

BASES

APPLICABLE SAFETY ANALYSES

Plant operators may employ the PORVs to depressurize the RCS in response to certain plant transients if normal pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator.

The PORVs are also modeled in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR) criteria, pressurizer volume, or hot leg saturation are examined (Ref. 2). By assuming PORV actuation, the primary pressure remains below the high pressurizer pressure trip setpoint. The DNBR calculation is more conservative and the transient pressurizer water volume is maximized, and the hot leg saturation temperature is reduced for those transients assuming PORV operation. As such, this actuation is not required to mitigate these events, and PORV automatic operation is, therefore, not an assumed safety function.

Pressurizer PORVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR.

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open and energized with the capability to be closed, or closed and energized with the capability to be opened, since the required safety function is accomplished by manual operation. Although typically open to allow PORV operation, the block valves may be OPERABLE when closed to isolate the flow path of an inoperable PORV that is capable of being manually cycled (e.g., as in the case of excessive PORV leakage). Similarly, isolation of an OPERABLE PORV does not render that PORV or block valve inoperable provided the relief function remains available with manual action.

An OPERABLE PORV is required to be capable of manually opening and closing and not experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific acceptance criteria,

BASES

LCO (continued)	exists when conditions dictate closure of the block valve to limit leakage Satisfying the LCO helps minimize challenges to fission product barriers.
APPLICABILITY	In MODES 1, 2, and 3 (with all RCS cold leg temperatures above 368°F), the PORVs are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. Although not a required function, the PORVs OPERABILITY in MODES 1, 2, and 3 (with all RCS cold leg temperatures above 368°F) also serves the desired function of minimizing challenges to the pressurizer safety valves. The PORVs are also required to be OPERABLE in MODES 1, 2, and 3 (with all RCS cold leg temperatures above 368°F) for manual actuation to mitigate a Steam Generator Tube Rupture event. Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the LCO is applicable in MODES 1, 2, and 3 (with all RCS cold leg temperatures above 368°F). The LCO is not applicable in MODES 3 (with any RCS cold leg temperature ≤ 368°F) 4, 5, and 6 (with the reactor vessel head in place) when both pressure and core energy are decreased and the pressure surges become much less significant. LCO 3.4.12 addresses the PORV requirements in these MODES.
ACTIONS	Note 1 has been added to clarify that all pressurizer PORVs are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis). Note 2 provides an exception for LCO 3.0.4 which permits entry into MODES 1, 2, and 3 to perform cycling of the PORVs or block valves to verify their OPERABLE status in the event that testing was not satisfactorily performed in lower MODES. <u>A.1</u> PORVs may be inoperable and capable of being manually cycled (e.g., excessive seat leakage). In this condition, either the PORVs must be

BASES

ACTIONS

A.1 (continued)

restored or the flow path isolated within 1 hour. The associated block valve is required to be closed, but power must be maintained to the associated block valve, since removal of power would render the block valve inoperable. Although a PORV may be designated inoperable, it may be able to be manually opened and closed, and therefore, able to perform its function. PORV inoperability may be due to excessive seat leakage or other causes that do not prevent manual use and do not create a possibility for a small break LOCA. For these reasons, the block valve may be closed but the Action requires power be maintained to the valve. This Condition is only intended to permit operation of the plant for a limited period of time not to exceed the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition. Normally, the PORVs should be available for automatic mitigation of overpressure events and should be returned to OPERABLE and automatic actuation status prior to entering startup (MODE 2).

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

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

If one PORV is inoperable and not capable of being manually cycled, it must be either restored or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times of 1 hour are reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one PORV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status. If the PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

C.1 and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or

BASES

ACTIONS

C.1 and C.2 (continued)

place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of mitigating an event if the inoperable block valve is not full open. If the block valve is restored within the Completion Time of 72 hours, the PORV may be restored to automatic operation. If it cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

The Required Actions are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition. While it may be desirable to also place the PORV(s) in manual control, this may not be possible for all causes of Condition B or E entry with PORV(s) inoperable and not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunction(s)).

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, then 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 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 3 (with any RCS cold leg temperature $\leq$ 368°F), 4, 5, and 6 (with the reactor vessel head on), automatic PORV OPERABILITY may be required. See LCO 3.4.12.

BASES

ACTIONS (continued)

E.1, E.2, E.3, and E.4

If more than one PORV is inoperable and not capable of being manually cycled, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If one PORV is restored and one PORV remains inoperable, then the plant will be in Condition B with the time clock started at the time the remaining PORV was discovered to be inoperable. If no PORVs are restored within the Completion Time, then 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 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 3 (with any RCS cold leg temperature ≤ 368°F), 4, 5, and 6 (with the reactor vessel head on) automatic PORV OPERABILITY may be required. See LCO 3.4.12.

F.1 and F.2

If more than one block valve is inoperable, it is necessary to either restore the block valves within the Completion Time of 1 hour, or place the associated PORVs in manual control and restore at least one block valve within 2 hours. The Completion Times are reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation.

The Required Actions are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition. While it may be desirable to also place the PORV(s) in manual control, this may not be possible for all causes of Condition B or E entry with PORV(s) inoperable and not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunction(s)).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The PTLR provides the maximum allowable actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires both safety injection pumps and one centrifugal charging pump to be incapable of injection into the RCS and isolating the accumulators. The normal charging pump (NCP), in addition to one centrifugal charging pump flow, has been included in the analysis of design basis mass input overpressure transient. The term centrifugal charging pump refers to the safety related Emergency Core Cooling System (ECCS) pumps only. The pressure relief capacity requires either two redundant RCS relief valves or a depressurized RCS and an RCS vent of sufficient size. One RCS relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

BACKGROUND (continued)

With minimum coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the makeup control system deactivated or the safety injection (SI) actuation circuits blocked.

Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. If conditions require the use of more than one centrifugal charging pump for makeup in the event of loss of inventory, either the NCP or other ECCS pumps can be made available through manual actions.

The LTOP System for pressure relief consists of two PORVs with reduced lift settings, or two residual heat removal (RHR) suction relief valves, or one PORV and one RHR suction relief valve, or a depressurized RCS and an RCS vent of sufficient size. Two RCS relief valves are required for redundancy. One RCS relief valve has adequate relieving capability to prevent overpressurization for the required coolant input capability.

PORV Requirements

As designed for the LTOP System, each PORV is signaled to open if the RCS pressure approaches a limit determined by the LTOP actuation logic. The LTOP actuation logic monitors both RCS temperature and RCS pressure and determines when a condition not acceptable with respect to the PTLR limits is approached. The wide range RCS temperature indications are auctioneered to select the lowest temperature signal.

The lowest temperature signal is processed through a function generator that calculates a pressure limit for that temperature. The calculated pressure limit is then compared with the indicated RCS pressure from a wide range pressure channel. If the indicated pressure meets or exceeds the calculated value, a PORV is signaled to open.

The PTLR presents the PORV setpoints for LTOP. The setpoints are normally staggered so only one valve opens during a low temperature overpressure transient. Having the setpoints of both valves within the limits in the PTLR ensures that the Reference 1 limits will not be exceeded in any analyzed event.

When a PORV is opened in an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

BASES

BACKGROUND (continued)

RHR Suction Relief Valve Requirements

During LTOP MODES, the RHR System is operated for decay heat removal and low pressure letdown control. Therefore, the RHR suction isolation valves are open in the piping from the RCS hot legs to the inlets of the RHR pumps. While these valves are open the RHR suction relief valves are exposed to the RCS and are able to relieve pressure transients in the RCS.

The RHR suction isolation valves must be open to make the RHR suction relief valves OPERABLE for RCS overpressure mitigation. The RHR suction relief valves are spring loaded, bellows type water relief valves with pressure tolerances and accumulation limits established by Section III of the American Society of Mechanical Engineers (ASME) Code (Ref. 3) for Class 2 relief valves.

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 4) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. In MODE 3 (with any RCS cold leg temperature $\leq$ 368°F) and below, overpressure prevention falls to two OPERABLE RCS relief valves or to a depressurized RCS and a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, the LTOP System must be re-evaluated to ensure its functional requirements can still be met using the RCS relief valve method or the depressurized and vented RCS condition.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The PTLR contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 9 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

Mass Input Type Transients

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

Heat Input Type Transients

a. Inadvertent actuation of pressurizer heaters;

b. Loss of RHR cooling; or

c. Reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

The following are required with exception described below during the LTOP MODES to ensure that mass and heat input transients do not occur, which either of the LTOP overpressure protection means cannot handle:

a. Rendering both safety injection pumps and one centrifugal charging pump incapable of injection (there are no limitations on the use of the NCP during the LTOP MODES);

b. Deactivating the accumulator discharge isolation valves in their closed positions or by venting the affected accumulator; and

c. Precluding start of an RCP if secondary temperature is more than 50°F above primary temperature in any one loop. LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," provide this protection.

Operation below 350°F but greater than 325°F with all centrifugal charging and safety injection pumps OPERABLE is allowed for up to 4 hours. There are no limitations on the use of the NCP. During low pressure, low temperature operation all automatic safety injection

BASES

APPLICABLE SAFETY ANALYSES (continued)

actuation signals except Containment Pressure - High are blocked. In normal conditions a single failure of the ESF actuation circuitry will result in the starting of at most one train of safety injection (one centrifugal charging pump, and one safety injection pump). For temperatures above 325°F, an overpressure event occurring as a result of starting two pumps can be successfully mitigated by operation of both PORV's without exceeding Appendix G limit. Given the short time duration that this condition is allowed and the low probability of a single failure causing an overpressure event during this time, the single failure of a PORV is not assumed. Initiation of both trains of safety injection during this 4-hour time frame due to operator error or a single failure occurring during testing of a redundant channel are not considered to be credible accidents.

Although LTOP is required to be OPERABLE when RCS temperature is less than 368°F, operation with all centrifugal charging pumps and both safety injection pumps OPERABLE is acceptable when RCS temperature is greater than 350°F. Should an inadvertent safety injection occur above 350°F, a single PORV has sufficient capacity to relieve the combined flow rate of all ECCS pumps and the NCP. Above 350°F, two RCPs and all pressurizer safety valves are required to be OPERABLE. Operation of an RCP eliminates the possibility of a 50°F difference existing between indicated and actual RCS temperature as a result of heat transport effects. Considering instrument uncertainties only, an indicated RCS temperature of 350°F is sufficiently high to allow full RCS pressurization in accordance with Appendix G limitations. Should an overpressure event occur in these conditions, the pressurizer safety valves provide acceptable and redundant overpressure protection.

The Reference 9 analyses demonstrate that either one RCS relief valve or the depressurized RCS and RCS vent can maintain RCS pressure below limits when only one centrifugal charging pump (in addition to the NCP) is actuated. Thus, the LCO allows only one centrifugal charging pump OPERABLE during the LTOP MODES. Since neither one RCS relief valve nor the RCS vent can handle the pressure transient caused by accumulator injection, when RCS temperature is low, the LCO also requires accumulator isolation when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The isolated accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions.

Fracture mechanics analyses established the temperature of LTOP Applicability at 368°F.

BASES

APPLICABLE SAFETY ANALYSES (continued)

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in the PTLR. The setpoints are derived by analyses that model the performance of the LTOP System, assuming the mass injection transient of one centrifugal charging pump and the NCP injecting into the RCS and the heat injection transient of starting an RCP with the RCS 50°F colder than the secondary coolant. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the Reference 1 P/T limits will be met.

The PORV setpoints in the PTLR will be updated when the revised P/T limits conflict with the LTOP analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," discuss these examinations.

The PORVs are considered active components. Thus, the failure of one PORV is assumed to represent the worst case, single active failure.

RHR Suction Relief Valve Performance

The RHR suction relief valves do not have variable pressure and temperature lift setpoints like the PORVs. Analyses show that one RHR suction relief valve with a setpoint at or between 436.5 psig and 463.5 psig will pass flow greater than that required for the limiting LTOP transient while maintaining RCS pressure less than the P/T limit curve.

As the RCS P/T limits are decreased to reflect the loss of toughness in the reactor vessel materials due to neutron embrittlement, the RHR suction relief valves must be analyzed to still accommodate the design basis transients for LTOP.

The RHR suction relief valves are considered active components. Thus, the failure of one valve is assumed to represent the worst case single active failure.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 2.0 square inches is capable of mitigating the limiting LTOP transient. The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, one centrifugal charging pump OPERABLE, maintaining RCS pressure less than the maximum pressure on the P/T limit curve.

The RCS vent size will be re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

The RCS vent is passive and is not subject to active failure.

The LTOP System satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that the LTOP System is OPERABLE. The LTOP System is OPERABLE when the maximum coolant input or heat input bounded by that assumed in the analyses and required pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires that a maximum of zero safety injection pumps and one centrifugal charging pump be capable of injecting into the RCS, and all accumulator discharge isolation valves be closed and immobilized (when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR).

The LCO is modified by four Notes. Note 1 allows two centrifugal charging pumps to be made capable of injecting into the RCS for < 1 hour for pump swap operations. One hour provides sufficient time to safely complete the actual transfer and to complete the administrative controls and surveillance requirements associated with the swap. The intent is to minimize the actual time that more than one charging pump is physically capable of injection. This is accomplished by racking out the breaker for one pump or employing two independent means to prevent a pump start in accordance with SR 3.4.12.2.

Note 2 recognizes the Applicability overlap between LCO's 3.4.12 and 3.5.2 and states that two safety injection pumps and two centrifugal charging pumps may be made capable of injecting into the RCS:

BASES

LCO (continued)

(a) In MODE 3 with any RCS cold leg temperature < 368°F and ECCS pumps OPERABLE pursuant to LCO 3.5.2, "ECCS-Operating", and

(b) For up to 4 hours after entering MODE 4 from MODE 3 or the temperature of one or more RCS cold legs decreases below 325°F, whichever comes first.

Note 3 states that one or more safety injection pumps may be made capable of injecting into the RCS in MODES 5 and 6 when the RCS water level is below the top of the reactor vessel flange for the purpose of protecting the decay heat removal function.

Note 4 states that the accumulator may be unisolated when the accumulator pressure is less than the maximum RCS pressure for the existing RCS cold leg temperature as allowed by the P/T limit curves provided in the PTLR. The accumulator discharge isolation valve Surveillance is not required under these pressure and temperature conditions.

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs; or

   A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set to the limit required by the PTLR and testing proves its ability to open at this setpoint, and motive power is available to the two valves and their control circuits.

b. Two OPERABLE RHR suction relief valves; or

   An RHR suction relief valve is OPERABLE for LTOP when its RHR suction isolation valves are open, its setpoint is at or between 436.5 psig and 463.5 psig, and testing has proven its ability to open at this setpoint.

c. One OPERABLE PORV and one OPERABLE RHR suction relief valve; or

d. A depressurized RCS and an RCS vent.

   An RCS vent is OPERABLE when open with an area of ≥ 2.0 square inches.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the site boundary can receive for 2 hours during an accident is specified in 10 CFR 100 (Ref. 1). The limits on specific activity ensure that the doses are held to a small fraction of the 10 CFR 100 limits during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the site boundary to a small fraction of the 10 CFR 100 dose guideline limits. The limits in the LCO are standardized, based on parametric evaluations of offsite radioactivity dose consequences for typical site locations.

The parametric evaluations showed the potential offsite dose levels for a SGTR accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits. Each evaluation assumes a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensure that the resulting 2 hour doses at the site boundary will not exceed a small fraction of the 10 CFR 100 dose guideline limits following a SGTR accident. The SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant at the LCO limit and an existing reactor coolant steam generator (SG) tube leakage rate of 1 gpm. The safety analysis assumes the specific activity of the secondary coolant is at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.18, "Secondary Specific Activity."

The analysis for the SGTR accident establishes the acceptance limits for RCS specific activity. Reference to this analysis is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The analysis is performed for two cases of reactor coolant specific activity. One case assumes specific activity at 1.0 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the rate of iodine release into the reactor coolant by a factor of about 500 immediately after the accident. The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas activity in the reactor coolant assumes 1% failed fuel, which closely equals the LCO limit of $100/\bar{E}$ μCi/gm for gross specific activity.

The analysis also assumes a loss of offsite power at the same time as the reactor trip after SGTR event. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal.

The loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG atmospheric relief valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends.

The safety analysis shows the radiological consequences of an SGTR accident are within a small fraction of the Reference 1 dose guideline limits. Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limits shown in Figure 3.4.16-1, in the applicable specification, for more than 48 hours. The safety analysis has concurrent and pre-accident iodine spiking levels up to 60.0 μCi/gm DOSE EQUIVALENT I-131.

The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of a SGTR accident occurring during the established 48 hour time limit. The occurrence of an SGTR accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits.

The limits on RCS specific activity are also used for establishing standardization in radiation shielding and plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABILITY (continued)

the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 2) limit of 2200°F.

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. Accumulator isolation is only required when the accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature, as allowed by the P/T limit curves provided in the PTLR. This allows RCS cooldown without challenging cold overpressure protection systems and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulator contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. If the accumulators discharge following a large main steam line break with offsite power available, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these

BASES

ACTIONS

B.1 (continued)

conditions, the 24 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified in WCAP-15049-A, Rev. 1 (Ref. 5).

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and RCS pressure reduced to ≤ 1000 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If more than one accumulator is inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve should be verified to be fully open every 12 hours. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed valve could result in not meeting accident analyses assumptions. This Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.2 and SR 3.5.1.3

Every 12 hours, borated water volume and nitrogen cover pressure are verified for each accumulator. The limit on borated water volume is equivalent to ≥ 24% and ≤ 79.9% level. Only one set of non-safety channels (1 of 2) is required for water level and pressure indication. The 12-hour Frequency is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, a 12 hour Frequency usually allows the operator to identify changes before limits are reached. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator every 31 days since the static design of the accumulators limits the ways in which the concentration can be changed. The 31 day Frequency is adequate to identify changes that could occur from mechanisms such as dilution or inleakage. Sampling the affected accumulator within 6 hours after a 70 gallon increase (approximately 8% level) will identify whether inleakage has caused a reduction in boron concentration to below the required limit. It is not necessary to verify boron concentration if the added water inventory is from the refueling water storage tank (RWST) and the RWST has not been diluted since verifying that its boron concentration satisfies SR 3.5.4.3, because the water contained in the RWST is normally within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 4).

SR 3.5.1.5

Verification every 31 days that power is removed from each accumulator isolation valve operator when the RCS pressure is > 1000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only two accumulators would be available for injection given a single failure coincident with a LOCA. Since power is removed under administrative control, the 31 day Frequency will provide adequate assurance that power is removed.

This SR allows power to be supplied to the motor operated isolation valves when RCS pressure is ≤ 1000 psig, thus allowing operational

BASES

SURVEILLANCE REQUIREMENTS	SR 3.5.1.5 (continued) flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns. Should closure of a valve occur in spite of the interlock, the SI signal provided to the valves would open a closed valve in the event of a LOCA.
REFERENCES	1. USAR, Chapter 6. 2. 10 CFR 50.46. 3. USAR, Chapter 15. 4. NUREG-1366, February 1990. 5. WCAP-15049-A, Rev. 1, April 1999.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Seal Injection Flow

BASES

BACKGROUND

The function of the seal injection throttle valves (BG-V0198 through BG-V0201) during an accident is similar to the function of the ECCS throttle valves in that each restricts flow from the centrifugal charging pump header to the Reactor Coolant System (RCS).

The restriction on reactor coolant pump (RCP) seal injection flow limits the amount of ECCS flow that would be diverted from the injection path following an accident. This limit is based on safety analysis assumptions that are required because RCP seal injection flow is not isolated during safety injection (SI).

APPLICABLE SAFETY ANALYSES

All ECCS subsystems are taken credit for in the large break loss of coolant accident (LOCA) at full power (Ref. 1). The LOCA analysis establishes the minimum flow for the ECCS pumps. The centrifugal charging pumps are also credited in the small break LOCA analysis. This analysis establishes the flow and discharge head at the design point for the centrifugal charging pumps. The steam generator tube rupture and main steam line break event analyses also credit the centrifugal charging pumps, but are not limiting in their design. Reference to these analyses is made in assessing changes to the Seal Injection System for evaluation of their effects in relation to the acceptance limits in these analyses.

The LCO ensures that seal injection flow will be sufficient for RCP seal integrity but limited so that the ECCS trains will be capable of delivering sufficient water to match boiloff rates soon enough to minimize uncovering of the core following a large LOCA. It also ensures that the centrifugal charging pumps will deliver sufficient water for a small LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the charging pumps alone deliver sufficient fluid to overcome the loss and maintain RCS inventory. Figure 3.5.5-1 was developed using a conservative combination of plant data to establish a maximum flow rate for the seal injection line versus delta pressure between the RCS and charging pump header pressure. Based on the conservative data, Figure 3.5.5-1 ensures adequate flow to the reactor coolant pump seals while ensuring the safety analysis assumption for minimum ECCS flow is maintained while avoiding charging pump runout conditions. Seal injection flow satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The intent of the LCO limit on seal injection flow is to make sure that flow through the RCP seal water injection line is low enough to ensure that sufficient centrifugal charging pump injection flow is directed to the RCS via the injection points (Ref. 2).

The LCO is not strictly a flow limit, but rather a flow limit based on a flow line resistance. In order to establish the proper flow line resistance, a pressure and flow must be known. The flow line resistance is established by adjusting the RCP seal injection flow in the acceptable region of Figure 3.5.5-1 at a given pressure differential between the charging header and the RCS. The flow limits established by Figure 3.5.5-1 ensures that the minimum ECCS flow assumed in the safety analyses is maintained.

The limit on seal injection flow must be met to render the ECCS OPERABLE. If this condition is not met, the ECCS flow may be less than that assumed in the accident analyses.

APPLICABILITY

In MODES 1, 2, and 3, the seal injection flow limit is dictated by ECCS flow requirements, which are specified for MODES 1, 2, 3, and 4. The seal injection flow limit is not applicable for MODE 4 and lower, however, because high seal injection flow is less critical as a result of the lower initial RCS pressure and decay heat removal requirements in these MODES. Therefore, RCP seal injection flow must be limited in MODES 1, 2, and 3 to ensure adequate ECCS performance.

ACTIONS

A.1

With the seal injection flow exceeding its limit, the amount of charging flow available to the RCS may be reduced. Under this Condition, action must be taken to restore the flow to below its limit. The operator has 4 hours from the time the flow is known to be above the limit to correctly position the manual seal injection throttle valves and thus be in compliance with the accident analysis. The Completion Time minimizes the potential exposure of the plant to a LOCA with insufficient injection flow and provides a reasonable time to restore seal injection flow within limits. This time is conservative with respect to the Completion Times of other ECCS LCOs; it is based on operating experience and is sufficient for taking corrective actions by operations personnel.

BASES

BACKGROUND

Containment Cooling System (continued)

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

APPLICABLE SAFETY ANALYSES

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

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is 48.9 psig and the peak containment temperature is 386.5°F (experienced during an SLB). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.) The analyses and evaluations assume a unit specific power level ranging to 102%, one containment spray train and one containment cooling train operating, and initial (pre-accident) containment conditions of 120°F and 0 psig. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

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

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

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

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

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

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

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

LCO

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

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

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

B 3.7 PLANT SYSTEMS

B 3.7.4 Atmospheric Relief Valves (ARVs)

BASES

BACKGROUND

The ARVs, or the Steam Dump System to the condenser, provide a method for cooling the unit to residual heat removal (RHR) entry conditions, as discussed in the USAR, Section 10.3 (Ref 1). Further cooldown in conjunction with the RHR System is also possible. This is done in conjunction with the Auxiliary Feedwater System providing cooling water from the condensate storage tank (CST). The ARVs also provide the means to equalize pressure between the Reactor Coolant System and the ruptured steam generator following a postulated steam generator tube rupture event. The ARVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the Steam Dump System.

One ARV line for each of the four steam generators is provided. Each ARV line consists of one ARV and an associated manual block valve.

The ARVs are provided with upstream block valves to permit their being tested at power, and to provide an alternate means of isolation. The ARVs are equipped with pneumatic controllers to permit control of the cooldown rate.

The ARVs are provided with a pressurized gas supply of nitrogen that, on a loss of pressure in the normal instrument air supply, automatically supplies nitrogen to operate the ARVs. One accumulator supplies one ARV and one auxiliary feedwater control valve per steam generator. The nitrogen accumulator supply is sized to provide sufficient pressurized gas to operate the ARVs for the time required for Reactor Coolant System cooldown to RHR entry condition.

A description of the ARVs is found in Reference 1.

APPLICABLE SAFETY ANALYSES

The design basis of the ARVs is established by the capability to cool the unit to RHR entry conditions. The design safe shutdown requires two steam generators, each with one ARV. The unit can be cooled to RHR entry conditions with only one steam generator and one ARV, utilizing the cooling water supply available in the CST. The valves will pass sufficient flow at all pressures to achieve a 50°F per hour plant cooldown rate. The total capacity of the four valves is 15% of rated main steam flow at steam generator no-load pressure.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In the accident analysis presented in Reference 2, the ARVs are assumed to be used by the operator to cool down the unit to RHR entry conditions for accidents accompanied by a loss of offsite power. The main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator pressure below the design value. For the recovery from a steam generator tube rupture (SGTR) event in Reference 3, the operator is required to perform a RCS cooldown using two intact steam generators to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured steam generator. For SG overfill resulting from SGTR, RCS cooldown to RHR entry conditions using intact SG ARVs is necessary to terminate primary to secondary break flow. The time required to terminate the primary to secondary break flow for an SGTR is more critical than the time required to cool down to RHR conditions for this event and also for other accidents. Thus, the SGTR is the limiting event for the ARVs. The number of ARVs required to be OPERABLE to satisfy the SGTR accident analysis requirements is four. If a single failure of one occurs and another is associated with the ruptured SG, two ARVs would remain OPERABLE for heat removal and RCS cooldown, as discussed in Reference 3.

The ARVs are equipped with block valves in the event an ARV spuriously fails open or fails to close during use.

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

LCO

Four ARV lines are required to be OPERABLE. One ARV line is required from each of four steam generators to ensure that at least two ARV lines are available to conduct a RCS cooldown following an SGTR, in which one steam generator becomes unavailable due to a SGTR, accompanied by a single, active failure of a second ARV line on an unaffected steam generator. The block valves must be OPERABLE to isolate a failed open ARV line.

Failure to meet the LCO can result in the inability to achieve subcooling, consistent with the assumptions used in the steam generator tube rupture analysis, to facilitate equalizing pressures between the Reactor Coolant System and the ruptured steam generator. Failure to meet the LCO can also impact the recovery capability following a SG overfill scenario.

An ARV is considered OPERABLE when it is capable of providing controlled relief of the main steam flow and capable of fully opening and closing on demand and not experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific

BASES

LCO (continued)	acceptance criterion, exists when conditions dictate closure of the block valve to limit leakage. The nitrogen accumulator tanks supplying the turbine driven AFW pump control valves and the steam generator atmospheric relief valves ensure an eight hour supply for the pump and valves.
APPLICABILITY	In MODES 1, 2, and 3, the ARV lines are required to be OPERABLE. In MODE 4, the pressure and temperature limitations are such that the probability of a SGTR event requiring ARV operation is low. In addition, the RHR System is available to provide the decay heat removal function in MODE 4. Therefore, the ARV lines are not required to be OPERABLE in MODE 4. In MODE 5 or 6, an SGTR is not a credible event.
ACTIONS	<u>A.1</u> With one ARV line inoperable for reasons other than excessive leakage, action must be taken to restore the ARV line to OPERABLE status within 7 days. The 7 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE ARV lines, a nonsafety grade backup in the Turbine Bypass System, and MSSVs. Required Action A.1 is modified by a Note indicating that LCO 3.0.4 does not apply. <u>B.1</u> With two ARV lines inoperable for reasons other than excessive ARV seat leakage, action must be taken to restore all but one ARV line to OPERABLE status. Since the block valve can be closed to isolate an ARV, some repairs may be possible with the unit at power. The 72 hour Completion Time is reasonable to repair inoperable ARV lines, based on the availability of the Turbine Bypass System and/or MSSVs, and the low probability of an event occurring during the restoration period that would require the ARV lines.

BASES

ACTIONS (continued)

C.1

With three or more ARV lines inoperable for reasons other than excessive leakage, action must be taken to restore all but two ARV lines to OPERABLE status. Since the block valve can be closed to isolate an ARV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ARV lines, based on the availability of the Turbine Bypass System and MSSVs, and the low probability of an event occurring during this period that would require the ARV lines.

D.1 and D.2

Requiring a 30 day limit for restoring an ARV valve to OPERABLE status from inoperable, due to excessive seat leakage from the valve, provides assurance that the required number of ARVs will be available for plant cooldown. This action limits the period in which a block valve is closed due to excessive seat leakage of the ARV and minimizes the delay associated with manually opening a closed manual isolation valve (due to excessive seat leakage of the ARV). Required Actions D.1 and D.2 are modified by a Note indicating that LCO 3.0.4 does not apply.

E.1 and E.2

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

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the ARVs must be able to be opened remotely and throttled through their full range. This SR ensures that the ARVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing satisfies this requirement, and use of an ARV during a unit cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the required Inservice Testing Program Frequency. The Frequency is acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.4.2

The function of the block valve is to isolate a failed open or leaking ARV. Cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during unit cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. The Frequency is acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 10.3.
2. USAR, Chapter 15.
3. USAR, Section 15.6.3.

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. Feedwater Line Break (FWLB);

b. Main Steam Line Break; and

c. Loss of MFW.

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

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

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

LCO

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

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

BASES

LCO (continued)	the CST to an ESW supply and supplying AFW to two steam generators. The turbine driven AFW pump is required to be OPERABLE with redundant steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of automatically transferring the suction from the CST to an ESW supply and supplying AFW to any of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE. The inoperability of a single supply line or a single suction isolation valve from an ESW train to the turbine driven AFW pump causes a loss of redundancy in ESW supply to the pump but does not render the turbine driven AFW train inoperable. The supply line begins at the point where the ESW piping branches into two lines, one supplying the motor driven AFW pump and one supplying the turbine driven AFW pump, and ends at the suction of the turbine driven AFW pump (Ref. 3). Therefore, with one ESW train inoperable, the associated motor driven AFW train is considered inoperable; and one turbine driven AFW pump supply line is considered inoperable. However, the turbine driven AFW train is OPERABLE based on the remaining OPERABLE ESW supply line. The nitrogen accumulator tanks supplying the turbine driven AFW pump control valves and the steam generator atmospheric relief valves ensure an eight hour supply for the pump and valves. Although the AFW System may be used in MODE 4 to remove decay heat, the LCO does not require the AFW System to be OPERABLE in MODE 4 since the RHR System is available for decay heat removal.
APPLICABILITY	In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory, lost as the unit cools to MODE 4 conditions. In MODE 4 the AFW System may be used for heat removal via the steam generators but is not required since the RHR System is available and required to be OPERABLE in this MODE. In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

BASES

ACTIONS

A.1 (continued)

This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

If one CCW train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CCW train is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this period.

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR is modified by a Note indicating that the isolation of the CCW flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to manual vent/drain valves, and to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.2

This SR verifies proper automatic operation of the CCW valves servicing safety related components or isolating the nonsafety related portion of the system on an actual or simulated actuation signal. This SR applies to the CCW valves that receive a Safety Injection signal and the RCP thermal barrier valves receiving a High CCW flow signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. 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 unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. However, individual valves may be tested during power operation under appropriate administrative controls, and if an actual actuation occurs during operation credit may be taken for automatic operation of valves. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.7.3

This SR verifies proper automatic operation of the CCW pumps on an actual or simulated actuation signal. These actuation signals include Safety Injection and Loss of Power. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. However, pumps may be tested during power operation under appropriate administrative controls, and if an actual actuation occurs during operation credit may be taken for automatic starting of pumps. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 9.2.2.
2. USAR, Section 6.2.

B 3.7 PLANT SYSTEMS

B 3.7.13 Emergency Exhaust System (EES)

BASES

BACKGROUND

The Emergency Exhaust System serves both the auxiliary building and the fuel building. Following a loss of coolant accident (LOCA), safety related dampers isolate the auxiliary building, and the Emergency Exhaust System exhausts potentially contaminated air from the Emergency Core Cooling system (ECCS) areas and from the Hydrogen Purge System.

The Emergency Exhaust System filters airborne radioactive particulates from the area of the fuel pool following a fuel handling accident. Following a LOCA, the system is aligned to the auxiliary building; however, a limited amount of air from the fuel building is processed through the Emergency Exhaust System to prevent excessive negative pressure in the auxiliary building. The Emergency Exhaust System, in conjunction with normally operating systems, also provides environmental control of temperature and humidity in the fuel pool area during fuel handling operations. One train of the system is manually started prior to initiating fuel handling operations.

The Emergency Exhaust System consists of two independent and redundant trains. Each train consists of a heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal absorber section for removal of gaseous activity (principally iodines), and a fan. Ductwork, dampers, and instrumentation also form part of the system, as well as heaters, functioning to reduce the relative humidity of the airstream. The system initiates filtered ventilation of the fuel building following receipt of a fuel building isolation signal.

The Emergency Exhaust System is on standby for an automatic start following receipt of a fuel building ventilation isolation signal (FBVIS) or a safety injection signal (SIS). Initiation of the LOCA (SIS) mode of operation takes precedence over any other mode of operation. In the LOCA mode the system is aligned to exhaust the auxiliary building.

Upon receipt of a fuel building ventilation isolation signal generated by gaseous radioactivity monitors in the fuel building exhaust line, normal air discharges from the building are terminated, the fuel building is isolated, and the stream of ventilation air discharges through the system filter trains.

BASES

BACKGROUND (continued)

The Emergency Exhaust System is discussed in the USAR, Sections 6.5.1, 9.4.2, 9.4.3, and 15.7.4 (Refs. 1, 2, and 3, respectively) because it may be used for normal, as well as post accident, atmospheric cleanup functions.

APPLICABLE SAFETY ANALYSES

The Emergency Exhaust System design basis is established by the consequences of the limiting Design Basis Accidents (DBAs), which are a loss of coolant accident (LOCA) and a fuel handling accident (FHA). The analysis of the fuel handling accident, given in Reference 3, assumes that all fuel rods in an assembly are damaged, and one of the Emergency Exhaust System filter-adsorber unit is operating with a failed heater or humidistat. A reduced efficiency in the removal of organic iodine would occur if the heater failure occurred concurrently with high ambient relative humidity. The analysis of the LOCA assumes that radioactive materials leaked from the ECCS and Containment Spray System during the recirculation mode are filtered and adsorbed by the Emergency Exhaust System. The DBA analysis of the LOCA assumes that only one train of the Emergency Exhaust System is functional due to a single failure that disables the other train. The accident analysis accounts for the reduction in airborne radioactive material provided by the one remaining train of this filtration system. The amount of fission products available for release from the fuel handling building is determined for a fuel handling accident and for a LOCA. These assumptions and the analysis follow the guidance provided in Regulatory Guides 1.4 (Ref. 5) and 1.25 (Ref. 4).

The Emergency Exhaust System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the Emergency Exhaust System are required to be OPERABLE to ensure that at least one train is available, assuming a single failure that disables the other train, coincident with a loss of offsite power. Total system failure could result in the atmospheric release from the auxiliary building or fuel building exceeding the guideline limits of 10 CFR 100 (Ref. 5) limits in the event of a LOCA or fuel handling accident.

The Emergency Exhaust System is considered OPERABLE when the individual components necessary to control releases from the auxiliary or fuel building are OPERABLE in both trains. An Emergency Exhaust System train is considered OPERABLE when its associated:

BASES

LCO (continued)

a. Fan is OPERABLE;

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

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

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

APPLICABILITY

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

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

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

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

BASES

ACTIONS

A.1

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

B.1

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

C.1 and C.2

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

D.1 and D.2

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

BASES

ACTIONS

D.1 and D.2 (continued)

If the system is not placed in operation, this action requires suspension of fuel movement, which precludes a fuel handling accident. This does not preclude the movement of fuel assemblies to a safe position.

E.1

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

F.1

During movement of irradiated fuel assemblies in the fuel building, when two trains of the Emergency Exhaust System are inoperable for reasons other than an inoperable fuel building boundary (i.e., Condition E), or if Required Action E.1 cannot be completed within the associated Completion Time action must be taken to place the unit in a condition in which the LCO does not apply. Action must be taken immediately to suspend movement of irradiated fuel assemblies in the fuel building. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

Standby systems should be checked periodically to ensure that they function properly. As the environmental and normal operating conditions on this system are not severe, testing each train once every month, by initiating from the control room flow through the HEPA filters and charcoal adsorbers, provides an adequate check on this system.

Monthly heater operation dries out any moisture accumulated in the charcoal from humidity in the ambient air. Systems with heaters must be operated for ≥ 10 continuous hours with the heaters energized. Operating heaters would not necessarily have the heating elements energized continuously for 10 hours, but will cycle depending on the temperature. The 31 day Frequency is based on the known reliability of the equipment

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1 (continued)

and the two train redundancy available. This SR can be satisfied with the Emergency Exhaust System in the SIS or FBVIS lineup during testing.

SR 3.7.13.2

This SR verifies that the required Emergency Exhaust System filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The Emergency Exhaust System filter tests are based on the guidance in References 6 and 7 in accordance with the VFTP. The VFTP includes testing HEPA filter performance, charcoal absorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal. Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.13.3

This SR verifies that each Emergency Exhaust System train starts and operates on an actual or simulated actuation signal. The 18 month Frequency is consistent with References 6 and 7. Proper completion of this SR requires testing the system in both the SIS (auxiliary building exhaust) and the FBVIS (fuel building exhaust) modes of operation.

During emergency operations the Emergency Exhaust System will automatically start in either the SIS or FBVIS lineup depending on the initiating signal. In the SIS lineup, the fans operate with dampers aligned to exhaust from the auxiliary building and prevent unfiltered leakage. In this SIS lineup, each train is capable of maintaining the auxiliary building at a negative pressure at least 0.25 inches water gauge relative to the outside atmosphere. In the FBVIS lineup, which is initiated on a Spent Fuel Pool Gaseous Radioactivity - High Signal, the fans operate with the dampers aligned to exhaust from the fuel building to prevent unfiltered leakage. In the FBVIS lineup, each train is capable of maintaining the fuel building at a negative pressure at least 0.25 inches water gauge relative to the outside atmosphere. Normal exhaust air from the fuel building is continuously monitored by radiation detectors. One detector output will automatically align the Emergency Exhaust System in the FBVIS mode of operation. This surveillance requirement demonstrates that each Emergency Exhaust System unit can be automatically started and properly configured to the FBVIS or SIS alignment, as applicable, upon receipt of an actual or simulated SIS signal and an FBVIS signal. It is not required that each Emergency Exhaust System unit be started from both

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.13.3 (continued)

actuation signals during the same surveillance test provided each actuation signal is tested independently within the 18 month test frequency.

SR 3.7.13.4

This SR verifies the integrity of the auxiliary building enclosure. The ability of the auxiliary building to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the Emergency Exhaust System. During the SIS mode of operation, the Emergency Exhaust System is designed to maintain a slight negative pressure in the auxiliary building, to prevent unfiltered leakage. The Emergency Exhaust System is designed to maintain a negative pressure ≥ 0.25 inches water gauge with respect to atmospheric pressure at a flow rate specified in the VFTP. The Frequency of 18 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref.8).

An 18 month Frequency (on a STAGGERED TEST BASIS) is consistent with Reference 9.

SR 3.7.13.5

This SR verifies the integrity of the fuel building enclosure. The ability of the fuel building to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the Emergency Exhaust System. During the FBVIS mode of operation, the Emergency Exhaust System is designed to maintain a slight negative pressure in the fuel building, to prevent unfiltered leakage. The Emergency Exhaust System is designed to maintain a negative pressure ≥ 0.25 inches water gauge with respect to atmospheric pressure at a flow rate specified in the VFTP. The Frequency of 18 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref.8).

An 18 month Frequency (on a STAGGERED TEST BASIS) is consistent with Reference 9.

BASES

REFERENCES

1. USAR, Section 6.5.1.
2. USAR, Section 9.4.2 and 9.4.3.
3. USAR, Section 15.7.4.
4. Regulatory Guide 1.25, Rev. 0 (Safety Guide 25).
5. 10 CFR 100.
6. ASTM D 3803-1989.
7. ANSI N510-1980.
8. NUREG-0800, Section 6.5.1, Rev. 2, July 1981.
9. Regulatory Guide 1.52 (Rev. 2).

B 3.7 PLANT SYSTEMS

B 3.7.16 Fuel Storage Pool Boron Concentration

BASES

BACKGROUND

In the High Density Rack (HDR) design (Refs. 1 and 2), each fuel pool storage rack location is designated as either Region 1, Region 2, Region 3, or empty (in the checkerboarding configuration). Numerous configurations of region designation are possible. Criteria are established for determining an acceptable configuration (Ref. 1). The HDRs will store a maximum of 2363 fuel assemblies in the spent fuel pool and potentially an additional 279 fuel assemblies in the cask loading pool with racks installed). Full-core offload capability will be maintained. The fuel storage pool consists of the spent fuel pool and the cask loading pool (with racks installed). 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 adsorber (IFBA); or up to a nominal maximum enrichment of 5.0 wt% U-235 with 16 IFBA; or spent fuel regardless of the discharge fuel burnup. Region 2 and 3 locations 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. Fuel assemblies not meeting the criteria of Figure 3.7.17-1 shall be stored in accordance with paragraph 4.3.1.1 in Section 4.3, Fuel Storage. Locations designated as empty cells shall contain no fuel assemblies.

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 HDR design is based on the use of unborated water, which maintains the fuel storage pool in a subcritical condition during normal operation with the fuel storage pool racks fully loaded. The double contingency principle discussed in ANSI N-16.1-1975 and the April 1978 NRC letter (Ref. 3) 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 scenario is associated with the accidental misloading of multiple fuel assemblies in non-Region 1 locations. This could potentially increase the reactivity of the fuel storage pool. To mitigate these postulated criticality related accidents, boron is dissolved in the pool water. Safe operation of the HDR with no movement of assemblies may therefore be achieved by controlling the location of

BASES

BACKGROUND (continued)	each assembly in accordance with LCO 3.7.17, "Spent Fuel Assembly Storage." Prior to movement of an assembly, it is necessary to perform SR 3.7.16.1.
APPLICABLE SAFETY ANALYSES	Accidents can be postulated that could increase the reactivity of the fuel storage pool which are unacceptable with unborated water in the fuel storage pool. Thus, for these accident occurrences, the presence of soluble boron in the storage pool maintains subcriticality with a K_{eff} of 0.95 or less. The postulated accidents are basically of two types. Multiple fuel assemblies could be incorrectly transferred to non-Region 1 locations (e.g., unirradiated fuel assemblies or insufficiently depleted fuel assemblies). The second type of postulated accidents is associated with a fuel assembly which is dropped adjacent to the fully loaded storage rack. The negative reactivity effect of the soluble boron compensates for the increased reactivity caused by either one of the two postulated accident scenarios. The accident analyses is provided in the USAR, Appendix 9.1A (Ref. 1). The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The fuel storage pool boron concentration is required to be ≥ 2165 ppm. The fuel storage pool consists of the spent fuel pool and cask loading pool (with racks installed). The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses of the potential critical accident scenarios as described in Reference 1. This concentration of dissolved boron is the minimum required concentration for non-inventoried fuel assembly storage and movement within the fuel storage pool.
APPLICABILITY	This LCO applies whenever fuel assemblies are stored in the fuel storage pool, until a complete fuel storage pool verification has been performed following the last movement of fuel assemblies in the fuel storage pool. This LCO does not apply following the verification, since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movements in progress, there is no potential for misloaded fuel assemblies or a dropped fuel assembly.

BASES

ACTIONS

A.1, A.2.1, and A.2.2

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

When the concentration of boron in the fuel storage pool is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. An acceptable alternative is to verify by administrative means that the fuel storage pool verification has been performed since the last movement of fuel assemblies in the fuel storage pool. However, prior to resuming movement of fuel assemblies, the concentration of boron must be restored. This does not preclude movement of a fuel assembly to a safe position.

If the LCO is not met while moving fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

This SR verifies that the concentration of boron in the fuel storage pool is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The 7 day Frequency is appropriate because no major replenishment of pool water is expected to take place over such a short period of time.

REFERENCE

1. USAR, Appendix 9.1A, "The High Density Rack (HDR) Design Concept."

2. Letter ET 98-0009, dated March 20, 1998, and subsequent license amendment.

3 Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

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).

BASES

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. Similarly, momentary

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

Each diesel generator (DG) is provided with a storage tank having a fuel oil capacity sufficient to operate that diesel for a period of 7 days at rated continuous capacity (Ref. 1). The post accident load demand is below the rated continuous capacity of the DG, which ensures the DG has sufficient fuel oil to perform its design function after an accident. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from storage tank to day tank by a transfer pump associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve or tank to result in the loss of more than one DG. The outside tanks, pumps, and piping are located underground. The oil fill connection to the underground storage tank is located above grade.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. The contained volume of lube oil in each diesel engine crankcase is sufficient to allow full load operation for greater than 7 days. With a contained volume equivalent to the "add oil" mark on the dipstick, a 10 day supply is available to support full load operation of the engine. The lube oil system is designed with an automatic makeup supply that begins makeup before the low level alarm is received and before reaching the "add oil" level on the dipstick.

BASES

BACKGROUND (continued)

The capacity and controls associated with the lube oil system are sufficient to ensure a minimum of 7 days of operation. Refer to the table below:

Description	Approximate Crankcase Volume
High level alarm	1215 gallons
Dipstick "full" mark	1200 gallons
Automatic Makeup valve isolates	1143 gallons
Automatic makeup valve opens	1063 gallons
Low level alarm	963 gallons
Dipstick "add oil" mark (10 day supply)	948 gallons
7 day supply	750 gallons
6 day supply	686 gallons
Unusable volume in crankcase	300 gallons

The dipstick is not capable of measuring below 948 gal; levels below this amount are measured using alternate methods.

Each DG has an air start system with adequate capacity for five successive start attempts on the DG without recharging the air start receiver(s). The air start system for each DG has two redundant trains each with a separate air receiver. A single train has adequate capacity for five successive start attempts without recharging; however, a single receiver must be at a higher air pressure than two receivers to support this starting capability.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR, Chapter 6 (Ref. 4), and in the USAR, Chapter 15 (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Since diesel fuel oil, lube oil, and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of the 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lubricating oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources- Operating," and LCO 3.8.2, "AC Sources - Shutdown."

The starting air system is required to have a minimum capacity for five successive DG start attempts without recharging the air start receivers.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required level, or feed and bleed operations, which may be necessitated by increasing particulate levels or any number of other oil quality degradations. This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required

BASES

ACTIONS

A.1 (continued)

prior to addition of fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

With lube oil inventory < 750 gal, sufficient lubricating oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. This restriction allows sufficient time to obtain the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.3. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling and re-analysis of the DG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

b. Verify in accordance with the tests specified in ASTM D975-81 (Ref. 6) that the sample has an API Gravity of within 0.3 degrees at 60°F, or a specific gravity of within 0.0016 at 60/60°F when compared to the supplier's certificate, or an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 27°F and ≤ 39°F, a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of ≥ 125°F; and

c. A water and sediment content of ≤ 0.05% when tested in accordance with ASTM D1796-83.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-81 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-81 (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 (Ref. 6), ASTM D4294-90, or ASTM D2622-82 (Ref. 6). If the sulpher analysis is performed using ASTM D129 (as specified by ASTM D975-81), ion chromatography may be used as an alternative to the gravimetric analysis. The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined based on ASTM D2276-83, Method A (Ref. 6). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. The filter size for the determination of particulate contamination will be 3.0 microns instead of 0.8 micron as specified by ASTM D2276-83. The filtered amount of diesel fuel oil will be approximately one liter, when possible. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles without recharging. A start cycle is defined as 3 seconds of cranking time or approximately 2 to 3 engine revolutions. The pressures specified in this SR are intended to reflect the lowest value at which the five starts can be accomplished with air supplied from one or two receivers.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.5

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 storage 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, and contaminated fuel oil, and from 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. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance.

BASES

REFERENCES (continued)

9. IEEE-450-1995.

10. Regulatory Guide 1.32, February 1977.

11. Regulatory Guide 1.129, December 1974.

12. NRC letter (J. Stone to O. Maynard) dated February 10, 1997: "Wolf Creek Generating Station - Amendment No. 104 to Facility Operating License No. NPF-42."

13. NRC Inspection Report 50-482/98-12, Paragraph e.16.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters - Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the AC vital buses because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the vital buses. The inverters are normally powered from the respective 125 VDC bus. An alternate source of power to the AC vital buses is provided from Class 1E constant voltage (Sola) transformers. The battery bus provides an uninterruptible power source for the instrumentation and controls for the Reactor Protection System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). Specific details on inverters and their operating characteristics are found in the USAR, Chapter 8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR, Chapter 6 (Ref. 2) and Chapter 15 (Ref. 3), assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required AC vital buses OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

Inverters satisfy Criterion 3 of the 10 CFR 50.36(c)(2)(ii).

LCO

The inverters ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

BASES

LCO (continued)

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The four inverters (two per train) ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 4.16 kV safety buses are de-energized.

Operable inverters require the associated vital bus to be powered by the inverter with output voltage within tolerances, and power input to the inverter from a 125 VDC battery bus.

The required inverters/AC vital buses are associated with the AC load group subsystems (Train A and Train B) as follows:

TRAIN A		TRAIN B	
Bus NN01 energized from Invert. NN11 connected to DC bus NK01	Bus NN03 energized from Invert. NN13 connected to DC bus NK03	Bus NN02 energized from Invert. NN12 connected to DC bus NK02	Bus NN04 energized from Invert. NN14 connected to DC bus NK04

APPLICABILITY

The inverters 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.

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, "Inverters - Shutdown."

ACTIONS

A.1

With a required inverter inoperable, its associated AC vital bus is inoperable until it is re-energized from its Class 1E constant voltage (Sola) transformer. The constant voltage (Sola) transformer powered from a Class 1E bus may be aligned to the vital bus by manually operating a sliding link.

BASES

ACTIONS

D.1 (continued)

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

The second Completion Time for Required Action D.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition D is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

E.1 and E.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit 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 unit conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

F.1

With two trains with inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 15.
3. Regulatory Guide 1.93, December 1974.

BASES

BACKGROUND (continued)

LCO 3.3.6, "Containment Purge Isolation Instrumentation," during CORE ALTERATIONS or movement of irradiated fuel in containment.

When the minipurge system is not used in MODE 6, all four 18 inch valves are closed.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations and the emergency personnel escape lock during fuel movements (Ref. 1).

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 2). Fuel handling accident, analyzed in Reference 2, assumes dropping a single irradiated fuel assembly. The requirements of LCO 3.9.7, "Refueling Pool Water Level," and the minimum decay time of 100 hours prior to CORE ALTERATIONS ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the guideline values specified in 10 CFR 100. Standard Review Plan, Section 15.7.4, Rev. 1 (Ref. 3), defines "well within" 10 CFR 100 to be 25% or less of the 10 CFR 100 values. The acceptance limits for offsite radiation exposure will be 25% of 10 CFR 100 values.

Containment penetrations satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO limits the consequences of a fuel handling accident in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge penetrations and the personnel air lock. For the OPERABLE containment purge penetrations, this LCO ensures that each penetration is isolable by the Containment Purge Isolation System to ensure that releases through the valves are terminated, such that radiological doses are within the acceptance limit.

BASES

LCO (continued)

LCO 3.9.4.b is modified by a Note allowing an emergency escape air lock temporary closure device to be an acceptable replacement for an emergency air lock door.

LCO 3.9.4.c is modified by a Note allowing Penetration P-63 (Service air valves KA V-039 and KA V-118) and Penetration P-98 (Breathing air valves KB V-001 and KB V-002) to be unisolated under administrative controls.

APPLICABILITY

The containment penetration requirements are applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment because this is when there is a potential for a fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when CORE ALTERATIONS or movement of irradiated fuel assemblies within containment are not being conducted, the potential for a fuel handling accident does not exist. Therefore, under these conditions no requirements are placed on containment penetration status.

ACTIONS

A.1 and A.2

If the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the containment purge isolation valve not capable of automatic actuation, the unit must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending CORE ALTERATIONS and movement of irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open purge isolation valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment purge isolation signal. The SR specifies that containment penetrations P-63 and P-98 that are open under

LIST OF COMMITMENTS

The following table identifies those actions committed to by Wolf Creek Nuclear Operating Corporation (WCNOC) in this document. Any other statements in this submittal are provided for information purposes and are not considered to be commitments. Please direct questions regarding these commitments to Mr. Michael J. Angus, Manager Licensing and Corrective Action, at Wolf Creek Generating Station, (316) 364-4077.

COMMITMENT	Due Date/Event
None	N/A